



FREEMAN, SULLIVAN & CO.

A MEMBER OF THE FSC GROUP

Benefit-Cost Analysis for Advanced Metering and Time-Based Pricing: Final Appendices

March 26, 2008

Freeman, Sullivan & Co.
101 Montgomery St., 15th Floor
San Francisco, CA 94104

With assistance from:

MWConsulting



Prepared for:

Vermont Department of Public Service
112 State Street
Montpelier, VT 05620-2601

Prepared by Freeman, Sullivan & Co:
Stephen S. George, Ph.D.
Josh Bode, MPP

and MWConsulting:
Michael Wiebe

APPENDIX TABLE OF CONTENTS

APPENDIX A. NUMBER OF METERS	1
APPENDIX B. TECHNOLOGY ANALYSIS	2
B.1. Meter Costs	2
B.2. Network and Communication Costs	4
<i>B.2.1. Hardware and O&M Costs for AMI Networks</i>	<i>5</i>
<i>B.2.2. Meter Density and Number of Network Components</i>	<i>6</i>
B.3. Meter Data Management System Costs	13
APPENDIX C. OPERATIONAL BENEFIT ANALYSIS	15
C.1. Avoided Meter Reading Costs	15
C.2. Reduced Call Center Costs	17
C.3. Reduced Outage Management Costs	19
C.4. Remote connect/disconnect	21
APPENDIX D. DEMAND RESPONSE IMPACT ANALYSIS	22
D.1. Number of Customers Included in the Analysis	23
D.2. Load Shapes Underlying the Analysis	25
D.3. Annual Energy Use by Utility and Rate Class	27
D.4. Price Elasticities	30
<i>D.4.1. Residential Sector Price Responsiveness</i>	<i>32</i>
<i>D.4.2. C&I Sector Price Responsiveness</i>	<i>35</i>
<i>D.4.3. Sensitivity Analysis: Customer Responsiveness to Peak Time Rebates</i>	<i>36</i>
D.5. Retail Prices (base and time-varying)	37
D.6. Cost Based Peak Rebate Calculations	41
D.7. DR Impacts per Customer	42
D.8. Customer Participation/Awareness	47
APPENDIX E. AVOIDED CAPACITY, ENERGY & ENVIRONMENTAL COSTS	48
E.1. Avoided Generation Capacity Costs	48
<i>E.1.1. Determining Avoided Generation Capacity Value</i>	<i>48</i>
<i>E.1.2. Capacity Value and Escalation</i>	<i>49</i>
<i>E.1.3. Installed Capacity Requirements</i>	<i>50</i>
<i>E.1.4. How DR Helps Avoid Generation Capacity Costs</i>	<i>52</i>
E.2. Avoided Transmission & Distribution Capacity Costs	54
<i>E.2.1. Levelized T&D Capacity Value</i>	<i>55</i>

E.2.2. How Levelized Transmission and Distribution Capacity Costs Are Estimated	56
E.2.3. Avoided T&D Values Employed	56
E.3. Avoided Energy Costs	57
E.4. Environmental Benefits.....	58
APPENDIX F. RELIABILITY BENEFITS.....	59
F.1. Outage Duration Impacts	59
F.2. Estimating Outage Costs	60
F.3. Results	64
APPENDIX G. MISCELLANEOUS INPUTS	67
G.1. Weighted Average Cost of Capital	68
G.2. Customer Population Growth	68
G.3. General Inflation Rate.....	68
G.4. Tax Adjustment Factor	69
G.5. Coincident Peak Demand and Annual Electricity Use Growth Rates	69
G.6. Generation, Transmission, and Distribution Capacity Escalation Rates..	72
G.7. Labor Escalation Rate	75
APPENDIX H. DATA REQUEST SURVEY FORM	76

APPENDIX A. NUMBER OF METERS

Among the 10 utilities included in the analysis, the AMI infrastructure investment cost estimates, meter data management system costs, and operational benefits were based on the number of meters served by each utility. All single and three phase meters were included, including those for off-peak water heating and large industrial customers (who may already have interval meters). On the other hand, DR benefit estimates were based on the number of customers, some of whom were excluded from the benefit analysis as detailed in Appendix D.1.

Table A-1 presents the overall number of meters by type for each utility that underlie the cost analysis.

**Table A-1:
Number of Meters by Type**

Utility	Single Phase Meters	Other Meters	Total Meters
Burlington Electric	18,947	914	19,861
Central Vermont	171,691	8,471	180,162
Green Mountain Power	87,707	6,496	94,203
VEC	39,138	40	39,178
Washington Electric	10,265	0	10,265
Small Utilities [1]	20,597	512	20,409

[1] The estimate for the small utilities was developed by adding the total number of meters reported in response to the data request, except for Ludlow. The number of meters reported for Ludlow was roughly 700 fewer than the number of customers reported in response to the data request and in the utility Annual Reports delivered to DPS. Consequently, the number of meters reported by Ludlow was increased by 700 to match the number of customers.

For CVPS, GMP, VEC, WEC, and the smaller utilities, both the number of meters and the number of customers were projected to grow over time at the rate of 0.52% per year, as detailed in Appendix G. BED provided its own forecast of customer growth, equal to 0.39%

APPENDIX B. TECHNOLOGY ANALYSIS

This appendix documents the specific input values and assumptions employed in calculating AMI meter costs, network costs, and meter data management system (MDMS) costs.

B.1. METER COSTS

For each utility, the total cost for meters over the life of an AMI investment is a function of the following factors:

- The number of meters by type (e.g., single phase, three phase, etc.);
- Replacement strategy (e.g., retrofitting existing meters or replacing them with electronic meters);
- The average cost per meter by type, which differs between the deployment phase, when meters are purchased in bulk, and the post-deployment period when new meters are installed in future years either to replace failed meters or to support customer growth;
- The average installation cost during the initial deployment phase;
- Meter failure rate, including any variance due to incremental complexity from options additions;
- Meter warranty duration;
- Customer growth rates (these values were documented in Appendix A);
- The incremental hardware costs for additional functionality, such as remote connect/disconnect capability, home area network capability, meter memory, and others.

The number of single-phase and non-single phase meters in the base year for each utility was obtained through responses to a data request that was sent to each utility company. (See Appendix H for a copy of the data request that was sent out.) Table A-2 in Appendix A shows the number of meters by type and the total number of meters for each utility.

In recent years, competition has led to a situation where, currently, there are only marginal differences in meter costs across vendors for meters with the same functionality. Put another way, costs do not vary much for meters with radio transmitters versus those that use power line carrier technology given the same level of meter functionality. However, the associated AMI network infrastructure cost can vary dramatically on a per meter basis. The meter cost used in this analysis for each utility and technology option during the initial deployment phase is \$85 per meter for single phase meters and \$300 per meter for all other meters. These values are based on a review of public domain information filed by several utilities in support of their regulatory funding requests. Our analysis implicitly assumes that the smaller utilities in Vermont will be able to obtain similar pricing to that of the larger utilities through buying cooperatives or some other form of cooperative procurement process. If this is not true, the cost for these utilities may be higher.

Installation costs also vary by meter type and the volume of work to be contracted. The assumed installation cost for the initial AMI deployment phase is \$20 for single phase meters and \$75 for all other meters. These values assume that meter installation is outsourced and completed in an efficient manner over a relatively short time period. If meters are installed by utility personnel over an extended time period, costs could be higher. If Vermont's utilities could find a way to coordinate their efforts regardless of AMI technology selected, costs will be lower than if this is not possible.

Beyond the initial deployment phase, additional meter costs will be incurred to support customer growth as well as to replace failed meters. It is assumed that the cost per meter will be higher in future years because of the small number of meters being purchased each year. This is true of both AMI meters and standard meters. The relevant value for analysis purposes is the incremental cost of an AMI meter over and above what the cost of a standard meter would have been in the same year.¹ We assume that the cost for both single and polyphase AMI meters beyond the deployment phase is 150 percent of the cost during the deployment phase. The cost of standard replacement meters (both electromechanical and electronic) in small lots is assumed to equal roughly \$35 for a single phase meter and \$150 for a polyphase meter. Thus, the incremental cost of an AMI replacement/new meter compared with a standard meter is \$92.50 for single phase meters $[(\$85)(1.5) - \$35]$ and \$300 for a polyphase meter $[(\$300)(1.5) - \$150]$.

Installation costs for new and replacement meters beyond the initial deployment period do not factor into the analysis, based on the assumption that the installation costs are essentially the same regardless of whether an AMI or a standard meter are installed in future years and that the replacement rate is the same for both meter types. We have assumed an annual replacement rate equal to 1 percent for both AMI and standard meters.

Another factor that must be incorporated into the cost analysis is that AMI meters typically come with a warranty. During the warranty period, no incremental meter costs would be incurred under the AMI scenario for replacement meters, whereas costs would be incurred for meter replacement during the same period for standard meters. The warranty period for AMI meters appears to vary significantly across vendors and contracts. Some of the largest utilities have such strong bargaining power that they have been able to negotiate enhanced meter warranties compared with the industry standard which is closer to one year. For this analysis, we have assumed a 2 year warranty period for new AMI meters.

All of the meter cost estimates described above were adjusted for inflation using a general inflation rate equal to 2.5%.

The final major hardware cost estimate required to complete the analysis concerns the incremental cost needed to incorporate remote connect/disconnect capability into the AMI system. The net benefits associated with remote connect/disconnect functionality was only examined for BED, where the high rate of customer turnover (due in large part to the high concentration of student and multi-family customers) suggested that this functionality might

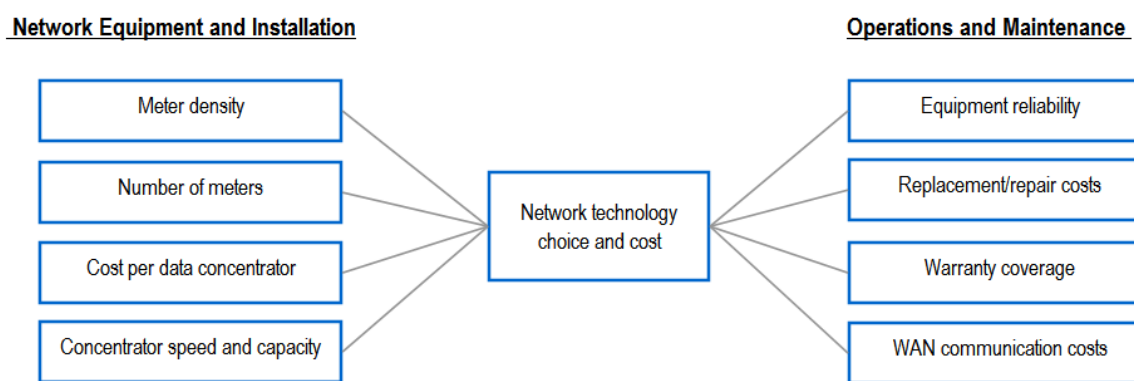
¹ A standard replacement meter might be an electromechanical or electronic meter. Many meter manufacturers are phasing out electromechanical meters so that, even in the absence of AMI, electronic kWh meters are being installed when an electromechanical meter fails. The prices for new electromechanical and "plain label" electronic meters are currently very similar and we have assumed they are equal in this analysis.

be cost-effective. Based on recent public domain information, we assume that the incremental cost to add this capability to AMI meters is \$50/meter. This estimate assumes a reasonably large volume. .

B.2. NETWORK AND COMMUNICATION COSTS

As with meters, the selection of and costs associated with the AMI communication network is based on a variety of factors. On a broad level, the drivers of overall cost can be divided into factors that affect the cost of the network equipment and factors that affect the cost of ongoing maintenance and operations. Figure B-1 shows the various factors that influence overall network costs.

Figure B-1
Factors Influencing Network Technology Costs



Section 3 of this report outlined the primary AMI technology options that are currently on the market. As explained there, for a given system functionality, key drivers of technology choice are meter density, measured in terms of meters per square mile for RF systems and meters per substation for PLC systems, and terrain, since hilly terrain can be quite limiting for star systems. Both density (or lack thereof) and terrain are potentially limiting factors in Vermont. Determining the best technology choice for each utility in Vermont would require a detailed propagation study, which was beyond the scope of this project. However, as described later in this section, we were able to consider the impact of density to some degree based on higher level data that was available.

As indicated in Section 3, broadband over power line (BPL) technology is a “non-starter” in Vermont due to the very low ratio of meters to transformers. Similarly, long-range star radio technology is a “non-starter” due to the relatively rural population and mountainous terrain in Vermont, which significantly diminishes the effective range of these systems. This is evident from the following “back-of-the-envelope” analysis.

The installed cost of a concentrator for short range star systems is on the order of \$2,000 whereas long-range star systems have an installed cost upwards of \$100,000 for a concentrator. With an effective range of up to 10 miles, in completely flat terrain, a long range system could in theory cover 300 square miles. Short range star systems have an effective range of perhaps 1 mile, which would provide coverage of 3 square miles. Thus, ignoring the need to overlap the concentrator coverage area for short range star systems in order to ensure full coverage, it would take 100 concentrators, at a cost of \$200,000, to

cover the same flat area that could be covered by a single long-range star system at a cost of \$100,000. Given the need for overlap, a short range star system might actually require more like 150 concentrators, making the long-range star system even more cost effective.

However, in Vermont, the relative cost effectiveness of the two systems is quite different. For example, the area with the most favorable characteristics for a long range star system is the BED service territory, which has roughly 20,000 meters spread over a relatively compact, flat 16 square-mile service territory. Assuming that a single, long-range star system could cover the entire service territory, the concentrator cost would equal \$100,000. With a short-range star system, ignoring the need for overlapping coverage areas, the 16 square miles could be covered using roughly 6 concentrators, at a cost of \$12,000. However, if we assume that the effective coverage for these systems is only 2 square miles rather than 3, in order to allow for overlapping coverage, we would need 8 concentrators at a cost of \$16,000. Even if you needed a concentrator for every 1 square mile, the cost would only equal \$32,000, which is much less than the \$100,000 cost for the long-range system. In short, the long-range star system is not cost-effective in Vermont even under the most favorable set of assumptions—the low concentration of customers combined with hilly terrain eliminates this technology option from detailed consideration.

B.2.1. Hardware and O&M Costs for AMI Networks

The preliminary analysis described above eliminated BPL and long-range star networks, which left three primary AMI technology options for detailed consideration: short-range star, mesh and PLC. Without the benefit of detailed propagation studies, it is impossible to adequately consider short-range star systems except in the BED service territory, which is compact and flat enough to allow for reasonable assumptions to be made in the absence of a propagation study. Consequently, we considered all three options for BED but only examined mesh and PLC for the remaining utilities.

Table B-1 contains estimates of the hardware and operating costs associated with the three technology options. For short-range star networks, a concentrator with an effective range of 2 square miles (taking into consideration the need for overlapping coverage areas) has an installed cost of \$2,000 and no practical limitation on the number of meters that it can handle. For PLC, there are two types of concentrators that vary with respect to cost and throughput capacity. Although both types are labeled low speed, the speed is sufficient to deliver hourly data for all meters within a 24-hour period. The higher capacity concentrators, with an installed cost of roughly \$35,000, will deliver data for up to 8,000 meters while the lower capacity concentrators have a maximum capacity of roughly 4,000 meters and an installed cost of approximately \$25,000. For mesh systems, concentrator costs are even lower than for star systems, but there may be a need to install repeaters, depending on the distance between meters. Concentrator costs are estimated to equal \$1,000 while repeaters have an estimated installed cost of roughly \$300.

Maintenance costs for all systems are based on an assumed failure rate of 5 percent per year and equipment and installation costs for replacement that are 50 percent higher than the initial costs.

The operation costs cover communication charges to deliver data from each concentrator to the MDMS using high-speed communication lines. The assumed cost is \$100 per month for each concentrator, or \$1,200 per year.

Table B-1
Network Technology Components and Costs

Network Type	Network Component	Equipment Cost <i>per unit</i>	Installation Cost <i>per unit</i>	Equipment Maintenance Costs* <i>per unit/year</i>	Operation Costs <i>per unit/year</i>
Fixed Radio Frequency					
	Star radio concentrator - short range	\$1,800	\$200	\$150.00	1,200
	Star radio concentrator - long range	\$95,000	\$5,000	\$7,500.00	1,200
Power Line Communications					
	Low speed, high capacity substation concentrator	\$30,000	\$5,000	\$2,625.00	1,200
	Low speed, medium capacity substation concentrator	\$22,000	\$3,000	\$1,875.00	1,200
Mesh Radio					
	Mesh radio concentrator	\$900	\$100	\$75.00	1,200
	Mesh radio repeaters	\$200	\$100	\$22.50	Not applicable

B.2.2. Meter Density and Number of Network Components

For all three of the primary network technology options considered, meter density affects the required number and type of network components. The type of meter density analysis required varies according to the network technology in question.

For the RF network technologies, estimating the number of data concentrators requires location-specific data including terrain details, in order to optimize the placement of data concentrators, ensure full coverage, and minimize costs. For a star network, where the data makes only one hop to the collector, it is important to know with great accuracy the GIS location of meters, whether they are indoors or outdoors, the terrain, the location and availability of poles and towers. Some star networks require the collector antenna to be located from 200 to 800 feet above ground. Most utilities do not own such towers where the spacing is at least one every 3 miles, resulting in the need to lease tower access from third parties.

For a mesh radio network, where data “hops” from one meter to the next, location-specific data is required even though the technology is highly adaptable to terrain and city or village contours. Specifically, the potential network gaps need to be identified in order to calculate the number of repeaters necessary to connect clusters of homes/buildings.

For PLC technologies, meter density per substation rather than geographical density is generally the driving factor of the number and type of data concentrators needed. This can be impacted by the required data rate as driven by the applications and their needs and in some cases may require the addition of repeaters on the power line which impacts the installed capital expenditures as well as life cycle operations costs. Some PLC technologies are sensitive to the distribution network's architecture and whether there are subsidiary substations that are directly tied to an upstream substation such that the aggregate meter population must be considered in determining the load and traffic capacity. Additionally the applications must be carefully considered with PLC systems as they tend to have more limited bandwidth and therefore less message carrying capacity as compared to most RF systems. For example, some PLC systems require utilities to "ping" (constantly request meter status) meters to determine whether or not a meter is energized. Pinging must be done at a frequency that meets the utility's goal for awareness of outages. If a utility wants to know on average within 90 seconds whether a customer has an outage then it must ping meters every 3 minutes. This can create product issues due to heating.

The point is that final network design requires substantial effort in all cases in order to ensure that the utility has an accurate design that meets its needs for the foreseeable future and that it does not find itself having to buy more network hardware over time as a result of a system that was poorly designed initially.

Star Network Technology

As described above, the mountainous terrain and rural nature of the population made it impossible to determine whether star technology might be cost-effective except in the relatively flat, compact BED service territory. For BED, in order to ensure full coverage, we assumed that one data concentrator would be required for every two square miles. Given the 15.5 square miles served by BED, this results in the need for 8 star concentrators.

Mesh Radio Technology

The number of data concentrators and repeaters required for a mesh network depends on the location of the customers and the area in question. For a given area, the required number of concentrators is determined either by the number of meters within range of a concentrator or the size of the coverage area. Vendors claim a maximum coverage area of 27 square miles. To be conservative, we used a value of 25 square miles. Mesh concentrators have a capacity ranging from a few hundred meters to roughly 3,000. We used a value of 3,000—given the relatively small number of concentrators required to support AMI in Vermont, the benefit-cost analysis is not terribly sensitive to this value. Based on our assumption of 3,000 meters per concentrator, if there were fewer than 3,000 meters in 25 square miles, one concentrator should cover that area. On the other hand, if there were 9,000 meters within the same 25 square mile area, three concentrators would be needed. Once again, a detailed propagation study would be required to determine the precise number of concentrators required for each utility. As an alternative, we used the following process to create a general estimate:

1. Calculate the number of data concentrators required if data capacity is the limiting factor, assuming a concentrator can support hourly pricing for 3,000 meters;

2. Calculate the number of data concentrators required if geography (sq. miles) is the limiting factor, assuming one concentrator for every 25 square miles;
3. For utilities where the number of meters is the limiting factor (BED only), use this value;
4. For utilities where the number of concentrators is greater using geography as the limiting factor use 75 percent of the value based on size;²
5. For the small utility group, use the number of concentrators based on size of territory, since these utilities are not contiguous and it is unlikely that they would be able to share the same concentrator to cover multiple service areas.

Table B-2 summarizes the estimates for each utility.

Table B-2
Calculation of Number of Mesh Concentrators

Utility	Sq. Mi.	# of Meters	# of Concentrators Needed		Base Case
			Based on Sq. Mi.	Based on # of Meters	
Burlington Electric	16	19,765	1	7	7
Central Vermont	4,178	173,365	167	58	125
Green Mountain Power	1,600	93,866	64	32	48
Washington Electric	1,197	10,238	48	4	36
Smaller Utilities	468	21,045	19	7	19

As with concentrators, determining the number of repeaters needed to cover any gaps between clusters of homes requires location specific information. In the absence of this, a proxy approach was used that assumes that repeaters are not needed in the more densely populated areas (cities and town centers), and that one repeater is needed for every X meters for the less dense areas outside of the cities and town villages, with X varying depending upon the size of the service territory.

To assess the number of data repeaters necessary to cover gaps between clusters of homes, the analysis relied on 1) Efficiency Vermont data that provided the distribution of service addresses³ by provider and by town or city, and 2) U.S. 2000 Census Data customized to identify Vermont towns and villages (or town centers) and their respective population and area (in sq. miles).⁴ The following steps were used to estimate the share of

² The actual number will depend on the extent to which customers are clustered throughout the service territory and the distances between clusters. Using 100 percent of this value almost certainly overstates the number of required concentrators.

³ Note that the determination of the number of repeaters is based on the number of service addresses whereas the concentrator estimate is based on the number of meters. In some service areas (e.g., CVPS) there is a relatively large number of service addresses with multiple meters. Since the number of repeaters is a function of the distance between meter locations, using the number of meters to determine the number of repeaters would overstate the required number of repeaters to bridge the gap between locations.

⁴ The town and village level data is available through the Vermont Center for Geographic Information and can be found at: <http://maps.vcgi.org/indicators/downloaddata.cfm>

meters served by each utility in urban areas (e.g., town village) and rural areas (e.g., outside the town village):

1. Calculate the share of service addresses served by each utility, by town, using the Efficiency Vermont database.
2. Allocate town villages to a specific utility if that utility serves 60 percent or more of the service addresses. This step was necessary because the available data sources provided information by town and towns are not exclusively served by a single provider.
3. Calculate the share of the town population that lives inside and outside of the town village (for towns with 1,000 or more meters) using the U.S. 2000 Census data.
4. Assume the proportion of the population living outside of the town village is similar to the proportion of service addresses outside of the town village.
5. Calculate the service addresses outside of the town village.

Table B-3 lists the estimated number of data repeaters under different assumptions about the number of repeaters needed to bridge the gap between locations for meters outside of a village. The final column shows the number of repeaters used in the base case scenario for each utility. Given the compact size of BED's service territory, we assumed that no repeaters would be needed. For CVPS, GMP and the small utility group, the number of meters per square mile ranges from 36 to 59, whereas the number for WEC is 8. As such, we based out estimate on 15 meters per repeater for CVPS, GMP and the small utility group, and on 5 meters per repeater for WEC.

Table B-3
Estimated Number of Repeaters Needed to Support Mesh Network

Utility	Service Addresses			# of Repeaters Needed Based on X Meters/Repeater			Base Case
	Total	In Town Village	Outside Town Village	5	10	15	
BED	19,548	19,548	0	0	0	0	0
CVPS	156,855	41,064	115,791	23,158	11,579	7,719	7,719
GMP	94,902	41,057	53,845	10,769	5,385	3,590	3,590
WEC	9,405	4,649	4,756	951	476	317	951
Small Utilities	17,020	2,692	14,328	2,865	1,433	955	955

Power Line Communications Technology

The key determinant of network costs for PLC technology is the number of substations and the cost per substation which is a function of the number of meters served by the substation. Recall the discussion earlier in this appendix that there are high capacity and low capacity

substation concentrators, with the former capable transmitting interval data for roughly 8,000 meters and the latter capable of serving roughly 4,000 meters. Given this, it was necessary to determine the number of substations that have meters above and below these thresholds.

Table B-4 shows the number of substations in Vermont and the number of meters connected to them based on data provided by the utilities.

Table B-4
Vermont Substations and Connected Meters

Substations Serving...	# of Substations	%	Meters	%	Avg Meters per substation
a. 1 Meter	3	1.1%	2	0.0%	0.7
b. 2–100 Meters	26	9.8%	615	0.2%	23.7
c. 101–500 Meters	55	20.7%	15,965	4.4%	290.3
d. 501–1,000 Meters	52	19.5%	37,444	10.4%	720.1
e. 1,001–3,000 Meters	106	39.8%	201,059	55.9%	1,896.8
f. 3,001–5,000 Meters	22	8.3%	90,340	25.1%	4,106.4
g. >5,000 Meters	2	0.8%	13,949	3.9%	6,974.5
Total	266	100.0%	359,374	100.0%	1,351.0

One of the complications of PLC system design is not knowing the relationship between substations and whether a master substation actually feeds one or more subsidiary substations. The report does not address this issue as the associated analysis is beyond the scope of the project. Thus the analysis assumes a conservative approach that does not realize any efficiencies that may be achievable but rather assumes each substation requires and PLC communication device.

Table B-5 shows the estimated number of data concentrators by type required for each utility. Table B-6 contains additional detail about the number of meters connected to substations by provider. Overall, roughly 95 percent of the substations have less than 4,000 meters connected to them.

Table B-5
Substations and Connected Meters by Utility

PROVIDER	High capacity Concentrators (>4000 customers)	Medium Capacity Concentrators (≤4000 customers)
BED	2	5
CVPS	4	94
GMP	3	49
VEC	0	68
WEC	0	8
Smaller Utilities	0	23
TOTAL	9	247

Given that the information requested from the utilities had bin categories that span the threshold of 4,000 meters, the share of meters with less than 4,000 connected meters had

to be estimated based on the distribution of meters per substation. This estimate was developed by using the information on average meters per substation from the bin data and fitting a distribution to the data using three goodness-of-fit tests⁵. The distribution was then used to estimate the proportion of substations with more than 4,000 connected meters. CVPS and GMP were sufficiently large to apply custom distributions. For BED, the statewide distribution was employed to calculate the share of meters above the 4,000 threshold. The analysis was not relevant to VEC, WEC, and the small utility group since VEC has already committed to a specific network technology and WEC and the smaller utilities clearly did not approach the threshold value.

⁵ The three goodness of fit test applied were the Anderson-Darling, Kolmogorov Smirnov, and Chi-Square tests

Table B-6
Substations and Connected Meters by Utility

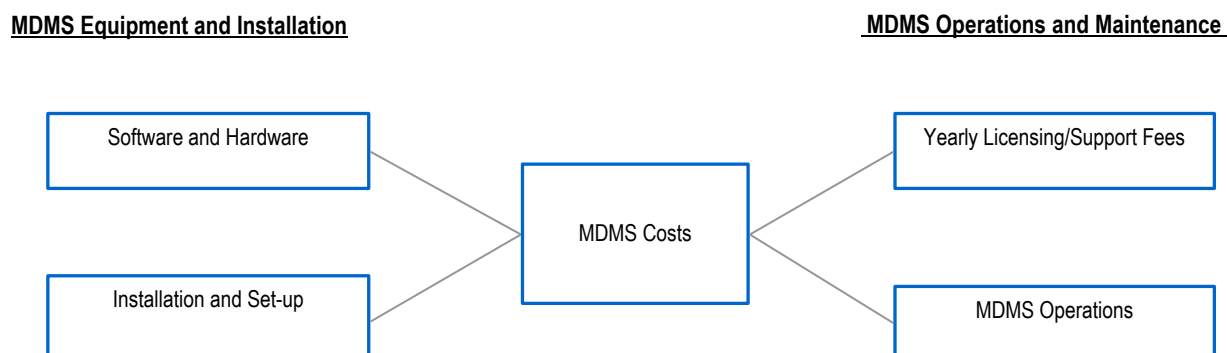
Provider	Substations Serving...	# of Substations	%	Meters	%	Avg. Meters per substation
BED	a. 1 Meter	0	0.0%	0	0.0%	0.0
	b. 2–100 Meters	0	0.0%	0	0.0%	0.0
	c. 101–500 Meters	2	28.6%	469	2.4%	234.5
	d. 501–1,000 Meters	1	14.3%	905	4.6%	905.0
	e. 1,001–3,000 Meters	2	28.6%	3,587	18.1%	1,793.5
	f. 3,001–5,000 Meters	0	0.0%	0	0.0%	0.0
	g. >5,000 Meters	2	28.6%	14,804	74.9%	7,402.0
	Total	7	100.0%	19,765	100.0%	2,823.6
CVPS	a. 1 Meter	0	0.0%	0	0.0%	0.0
	b. 2–100 Meters	7	7.1%	143	0.1%	20.4
	c. 101–500 Meters	9	9.2%	2,305	1.3%	256.1
	d. 501–1,000 Meters	14	14.3%	10,078	5.8%	719.9
	e. 1,001–3,000 Meters	56	57.1%	113,242	65.3%	2,022.2
	f. 3,001–5,000 Meters	11	11.2%	42,106	24.3%	3,827.8
	g. >5,000 Meters	1	1.0%	5,491	3.2%	5,491.0
	TOTAL	98	100.0%	173,365	100.0%	1,769.0
GMP	a. 1 Meter	0	0.0%	0	0.0%	0.0
	b. 2–100 Meters	5	9.6%	94	0.1%	18.8
	c. 101–500 Meters	6	11.5%	1,491	1.6%	248.5
	d. 501–1,000 Meters	8	15.4%	5,172	5.5%	646.5
	e. 1,001–3,000 Meters	25	48.1%	51,866	55.3%	2,074.6
	f. 3,001–5,000 Meters	7	13.5%	26,785	28.5%	3,826.4
	g. >5,000 Meters	1	1.9%	8,458	9.0%	8,458.0
	TOTAL	52	100.0%	93,866	100.0%	1,805.1
VEC	a. 1 Meter	1	1.5%	1	0.0%	1.0
	b. 2–100 Meters	8	11.8%	79	0.2%	9.9
	c. 101–500 Meters	33	48.5%	9606	24.5%	291.1
	d. 501–1,000 Meters	18	26.5%	14836	37.9%	824.2
	e. 1,001–3,000 Meters	6	8.8%	7971	20.4%	1,328.5
	f. 3,001–5,000 Meters	2	2.9%	6645	17.0%	3,322.5
	g. >5,000 Meters	0	0.0%	0	0.0%	0.0
	TOTAL	68	100.0%	39,138	100.0%	575.6
WEC	a. 1 Meter	0	0.0%	0	0.0%	0.0
	b. 2–100 Meters	1	12.5%	77	0.8%	77.0
	c. 101–500 Meters	0	0.0%	433	4.2%	0.0
	d. 501–1,000 Meters	1	12.5%	814	8.0%	814.0
	e. 1,001–3,000 Meters	6	75.0%	8,914	87.1%	1,485.7
	f. 3,001–5,000 Meters	0	0.0%	0	0.0%	0.0
	g. >5,000 Meters	0	0.0%	0	0.0%	0.0
	TOTAL	8	100.0%	10,238	100.0%	1,279.8
Smaller Utilities	a. 1 Meter	1	4.2%	1	0.0%	1.0
	- Hardwick	4	16.7%	92	0.4%	23.0
	- Lyndonville	2	8.3%	575	2.7%	287.5
	- Ludlow	9	37.5%	7,219	34.3%	802.1
	- Morrisville	8	33.3%	13,158	62.5%	1,644.8
	- Stowe*	0	0.0%	0	0.0%	0.0
	g. >5,000 Meters	0	0.0%	0	0.0%	0.0
	TOTAL	24	100.0%	21,045	100.0%	876.9

*Stowe number of meters by category estimated based on bins, number of substations, and overall meters

B.3. METER DATA MANAGEMENT SYSTEM COSTS

The meters provide the ability to collect hourly data remotely and monitor power conditions at the site level, and the network provides the means to communicate data from individual service address to a central points. The final primary component of an AMI network is the meter data management system (MDMS) necessary to facilitate billing for time-varying pricing. Figure B-2 provides a high level overview of the costs components of an MDM system.

Figure B-2



Utilities have two main options for obtaining MDMS functionality: 1) purchase the necessary hardware and software licenses and run the system in-house, or 2) outsource the meter data management. The first option requires more up-front investment, but also is associated with lower long term operation cost for larger utilities such as CVPS and GMP. On the other hand, outsourcing the MDMS requires a smaller up front investment and is also more viable option for smaller utilities, with outsourcing being available for utilities as small as 20,000 meters. This lower bound clearly raises question as to whether and how smaller utilities such as Washington Electric, Lyndonville, Ludlow, Hardwick, etc. could support the meter data management system required to enable time-based pricing. Technically, if the utilities have compatible billing systems, some synergies are possible.

Table B-7 lists the meter data management options and costs employed in the analysis. For CVPS and GMP, in-house data management was selected, with CVPS requiring \$600,000 in initial software, hardware, and set-up costs and GMP requiring \$500,000 in initial software, hardware, and set-up costs. The outsourcing option was employed as the base case in the BED, WEC, and smaller utilities analysis. In the case of WEC, and the smaller utilities an outsourcing option was assumed to be possible in the future, though currently meter data management outsourcing is only available for utilities with about 20,000 or more customers.

Given the relatively small population served by all of the Vermont utilities it may be that establishing a centralized MDMS service center could be a viable approach to meeting the needs of all at the lowest cost for all. This was outside the scope of this report and was not analyzed in detail.

Table B-7
Meter Data Management Options and Costs

<u>In-house Meter Data Management</u>	<u>Outsource Meter Data Management</u>
♦ Software, hardware, and set-up - \$500,000 to \$600,000	♦ Set-up - \$50,000
♦ Ongoing licensing for software and support - \$60,000 per year	♦ Operations cost - \$3 per meter/year
♦ Operations cost - \$1 per meter/year	

APPENDIX C. OPERATIONAL BENEFIT ANALYSIS

There is a wide variety of operational benefits that potentially can be obtained with the implementation of AMI. The focus of the analysis was in quantifying the following three main operational benefits based on the data provided by the utilities:

- Avoided meter reading costs
- Reduced call center costs
- Reduced outage management costs

In addition, because of their high account turnover, BED requested an analysis of the benefits associated with adding remote connect/disconnect capabilities to some of their meters. Incorporating remote connect/disconnect functionality in AMI meters significantly reduces the need to dispatch field crews to disconnect and reconnect the power when customers move or as a means of managing collections.

The analysis presented here was based primarily on information provided by the utilities through the data request that was initiated at the outset of the project (see Appendix H). In many cases, the details needed to develop estimates for certain benefit streams were not collected by a utility and, therefore, could not be provided. For example, most utilities in Vermont do not gather information on the number of calls by call type, making it very difficult to estimate reductions in call center costs associated with fewer estimated bills or complaints about meter readers. Hardly anyone was able to provide information on the cost of billing exceptions or manual billing operations. Importantly, utility budgeting and data tracking practices are not uniform within Vermont. As a result, the inputs employed in the analysis were gathered from, presented to, and vetted by individual utilities.

Where appropriate, if data was not provided by a specific utility, costs were estimated based on information provided by other utilities in Vermont, making judgmental adjustments based on differences in the number of meters, customers or other utility characteristics. When in doubt, an attempt was made to err on the conservative side. In a number of instances, savings were not counted even though they might be obtainable and quantifiable through more detailed, utility-specific business case analysis. As a result, the estimated operational savings probably undercount what is possible if AMI was deployed and fully integrated into business operations.

C.1. AVOIDED METER READING COSTS

Avoided meter reading costs generally comprise the majority of utility operational benefits. If a complete and detailed analysis were to be done, avoided meter reading costs should include the direct labor costs associated with regular and off-cycle read costs; the cost of employee benefits and overheads; reductions in post-employment benefits such as pension contributions and ongoing health costs after retirement; vehicles and materials, including hand-held reading devices (plus replacement of same); and any reduction in insurance or claims associated with safety and premise damages from meter reading activity. In many instances, it was not clear whether all of the above costs were included in the data provided by the utilities.

Table C-1 summarizes the information associated with meter reading activities obtained from the largest four utilities (except VEC) and for the small utility group as a whole. Table C-2 provides similar information for the five small utilities.

Table C-1
Meter Reads and Meter Reading Costs

	Category	BED	CVPS ^[1]	GMP ^[2]	WEC	Smaller Utilities ^[3]
Annual Meter Reads	Normal-Cycle Reads (annual)	237,180	2,139,533	571,000	123,036	238,044
	Off-cycle Reads (annual)	2,484	22,411		1,289	620
	TOTAL	239,664	2,161,944	571,000	124,325	238,664
Annual Costs	Labor Costs	\$61,025	\$2,478,296	\$340,000	\$110,000	
	Vehicles Costs		\$592,657	\$190,000		
	Other Meter Reading Costs	\$30,605	\$75,810		\$5,400	
	TOTAL	\$91,630	\$3,146,763	\$530,000	\$115,400	\$270,490
Costs per Manually Read Meter		\$0.38	\$1.46	\$0.95	\$0.93	\$1.13

- [1] CVPS labor costs do not match data response. Vehicle costs were separated from labor costs based on feedback from CVPS. Other meter reading costs include the cost associated with the operation and maintenance of handheld device (\$35,820) and the cost of remotely read meters (\$33,990)
- [2] GMP labor costs do not match data response. Vehicle costs were separated from labor costs based on feedback from GMP. Total meter reads were based on 2005 GMP filing. After discussions with GMP, the estimated number of meter reads provided in the data request was not employed because it undercounted customers by roughly 35,000.
- [3] Smaller utility costs were based on meter reading budgets provided in the data request. Only half the meter reading budget was included for Stowe as it also provides meter reading associated with water services.

Table C-2
Meter Reads and Meter Reading Costs for Five Small Utilities

Utility	Annual number of reads ^[1]	Annual Labor Cost	Annual Other Costs	Avg. Cost per meter read ^[2]	2005 meter reading budget	2006 meter reading budget
Hardwick	43,512	\$49,159	\$6,348	\$1.19	\$45,100	\$51,900
Ludlow ^[3]	44,988	\$35,766		\$0.80		
Lyndonville	66,552	\$5,546		\$0.92	\$61,747	\$61,324
Morrisville	45,216	\$56,155	\$3,500	\$1.42	\$65,000	\$64,000
Stowe ^[4]	45,912	\$57,500		\$1.25		

- [1] Number of reads calculate based on the frequency in which meters were read
- [2] 2006 meter reading budget divided by the number of meter reads. If meter reading budget was not provided the labor costs associated with meter reading were divided by the number of meter reads. For Stowe half the labor costs were employed.
- [3] For Ludlow, the estimated number of meters produced in response to the data request was less than the number of customers. The numbers of meters was adjusted upwards by 700 meters to correct the discrepancy.
- [4] Stowe provided both electric and water services. Only half of the annual meter reading labor cost was assumed to be associated with electric meters.

In calculating benefits, total meters read were assumed to grow in proportion to the growth in the customer population, equal to 0.52% per year for all utilities except BED, which provided its own forecast of customer growth at 0.39% per year. Meter reading costs were assumed to grow in tandem with the growth in total meters read. Finally, a separate escalation rate was employed for labor costs (3.5%) and other meter reading costs, which were assumed to grow at the general inflation rate (2.5%).

C.2. REDUCED CALL CENTER COSTS

The elimination of estimated bills and inaccurate meter reads can also reduce call center costs. The number of calls can be reduced in at least five areas: high bill inquiries due to inaccurate meter reads; bill inquiries associated with estimated bills; delayed bills due to unavailability of meter reads; and complaints about meter readers.

Most utilities in Vermont do not gather information on the number of calls by call type, making it very difficult to estimate reductions in call center costs associated with fewer estimated bills, complaints about meter readers, or outages. As a proxy, call center cost savings of 10 percent were applied to the call minutes that were not related to storms. The 10 percent call reduction is consistent with the call center savings estimates filed by Central Maine Power in their recent AMI business case filing.⁶ For context, the estimates used for the DR analysis were compared with the CVPS preliminary estimates of call center cost savings. CVPS provided the preliminary estimates in terms of dollars per meter-month. The value was converted into an annual savings estimates based on the number of single phase meters and roughly represented a 30% decrease in call center costs. As such, we believe the 10 percent estimate is conservative.

BED and GMP provided data on the overall call related budget, the number of calls, and total call minutes. In addition, GMP provided separate estimates of call duration for storm versus non-storm related calls. CVPS provided data on their overall budget and total number of calls, but did not have data on the number of call minutes. WEC only provided total call minutes and was not able to distinguish the share of its budget associated with customer service calls versus storm-related calls. For the smaller utilities, no call savings were assumed since the smaller utilities generally did not have separate call center budgets, and they generally did not have any personnel whose sole function is answering customer calls.

Table C-3 describes at a broad level the information used to calculate call center costs and the savings due to AMI. Values that were not directly provided by a utility but were estimated are indicated in bold and italicized font.

⁶ Docket No. 2007-215.

Table C-3
Call Center Cost Estimates

Call Related Information	BED ^[1]	CVPS ^[2]	GMP	WEC ^[3]
Call related budget	\$308,269	\$874,246	\$1,007,500	\$274,623
Number of annual calls	87,524	343,710	173,240	48,936
Average call duration	1.85	2.20	2.43	2.43
Total call minutes	161,919	756,088	420,880	118,898
Average cost per call minute	\$1.90	\$1.15	\$2.50	\$2.50
Call minutes used for analysis	161,919	659,418	388,880	109,849
Cost per call minute used for analysis	\$1.90	\$1.15	\$2.50	\$2.50
Base percent reduction in costs	0%	10%	10%	10%

[1] The BED base percent cost reduction was set at zero because most of the utility's calls are not related to billing but to service connection and disconnections. In addition, very few of their calls are related to storms or outages.

[2] CVPS provided data on total storm and non-storm related calls and its overall budget. The average call duration was estimated based on the GMP data on call duration of storm related and non-storm related calls. Average cost per call minute was based on the CVPS budget and the estimate of total call minutes.

[3] WEC provided data on total calls, but was unable to distinguish between storm and non-storm related calls, and did not identify the budget associated with customer calls. The estimates of overall call minutes, cost per call minute, and call minutes not associated with storms were based on the GMP data. BED data was not applied because of its significantly smaller geographic footprint, substantially lower reliability indices (likely due to terrain and underground wires), different customer demographics, and lack of distinction between storm related and non-storm related calls.

Overall, call center cost savings will likely be a function of not only the type and quantity of calls currently received, but of how customer calls are currently handled. Utilities that have call systems with less automation are likely to experience higher cost savings. Given this, in practice, the percent reduction in call center costs will likely vary by utility.

Table C-4 provides the annual call center savings (in 2006 dollars) associated with different levels of reductions in call minutes. For the analysis presented here, call center costs were assumed to grow in proportion to population growth (0.5%) and were adjusted for inflation (2.5%) prior to discounting. During the meter deployment period, the savings were assumed to occur in proportion to the number of meters installed and connected to the network.

Table C-4
Annual Call Center Savings Sensitivity Analysis

Utility	% Reduction in Call Minutes							
	2.5%	5.0%	7.5%	10.0%	12.5%	15.0%	17.5%	20.0%
BED	\$7,691	\$15,382	\$23,073	\$30,765	\$38,456	\$46,147	\$53,838	\$61,529
VPS	\$19,035	\$38,070	\$57,105	\$76,140	\$95,175	\$114,210	\$133,245	\$152,280
GMP	\$24,305	\$48,610	\$72,915	\$97,220	\$121,525	\$145,830	\$170,135	\$194,440
WEC	\$6,866	\$13,731	\$20,597	\$27,462	\$34,328	\$41,193	\$48,059	\$54,925

C.3. REDUCED OUTAGE MANAGEMENT COSTS

AMI systems with two-way communications can be used to reduce utility outage management costs. This benefit is in addition to the customer reliability benefit associated with reduced outage durations, which is discussed in appendix F. The AMI system can “ping” a meter when a customer calls regarding an outage to determine whether or not the outage is on the customer’s side of the meter, thus avoiding unnecessarily dispatching a field crew. Outage detection can also help reduce outage duration and restoration costs during wide scale outages by detecting whether or not power has been successfully restored everywhere while crews are still in the field, thus avoiding crew re-dispatch.

From a utility perspective, AMI reduced cost associated with field crews and field trips. As result, the analysis quantifying avoided outage management cost is grounded on:

- The number of avoided field trips for each utility associated with outages on the customer side and the costs associated with the field trips
- A 10 percent reduction in the overall storm related budget due to avoided crew re-dispatches associated with incomplete outage restoration efforts.

Table C-5 summarizes outage related field trips associated due to outages on the customer side or on the utility side of the meter. Only CVPS and GMP were able to provide data on the number of field trips and the costs per trip, and only CVPS distinguished between trips due to actual utility outages and trips associated with outages on the customer side of the meter. Given that outages on the customer side (false alarms) are unrelated to actual reliability indices and do not vary by geography or density, the CVPS data on number of outages on the customer side could be extrapolated to other utilities in proportion to the residential customer population. On the other hand, trip costs do vary based on the density and geography of the utility, as reflected by the differences in cost per field trip between GMP (\$150 per trip) and CVPS (\$275 per trip). For BED, the GMP cost per trip was used, since both utilities operate in more urban areas. For WEC, the CVPS costs were used since both utilities have a low number of customers per square mile.

Table C-5
Costs Associated with “No Light” Field Calls

Utility	# of Customers	Field trips for outages on customer side per thousand customers	Estimated field trips for outages on customer side	Average Cost per Trip	Annual Costs
BED	16,197	2.65	43	\$150.00	\$6,452
CVPS	131,483	2.65	349	\$275.00	\$95,975
GMP	78,367	2.65	208	\$150.00	\$31,202
WEC	9,917	2.65	26	\$275.00	\$7,242

Without AMI in place, field trips associated with outages on the customer side were assumed to grow in proportion to the residential customer growth. The average cost per trip was assumed to grow at the general inflation rate of 2.5 percent.

Outage detection can also help reduce outage duration and restoration costs during wide scale outages. It is not uncommon during a large-scale outage for field crews to be dispatched to a new location after thinking that service had been fully restored in an area when in fact it had not. Returning crews to the original location to clean up remaining outage pockets is costly. PPL estimates that it has achieved a 10 percent reduction in restoration costs during major storms using its AMI system to better manage field operations. Like Vermont, the utility has a relatively rural customer population, hilly terrain, and somewhat similar weather. Importantly, the estimates for PPL are based on years of experience with AMI, not on projected savings.

Table C-6 summarizes the estimated storm and non-storm related field operations budgets. Both GMP and WEC provided their storm and non-storm related field operations budget. For GMP, storm related costs constituted 18.4 percent of its overall budget. For WEC, they constituted 14.1 percent of their overall field operation budget. CVPS provided its total field operations budget and did not distinguish storm-related expenses from other expenses. The storm-related budget for CVPS was based on weighting the GMP and WEC share of their budget associated with storm expenses and applying it to CVPS. BED did not provide any information about its field operations budget. However, the differences in geography, customer density, underground wires, and most importantly reliability indices made it difficult to justifiably apply proportions from GMP or WEC. Overall, BED reliability indices are substantially lower than for the rest of the state.

Table C-6
Estimates of Storm Restoration Budgets

UTILITY	Annual Budget		TOTAL
	Non-storm Related	Storm Budget	
BED	N/A	N/A	N/A
CVPS	\$4,786,663	\$1,048,410	\$5,835,073
GMP	\$3,192,000	\$720,000	\$3,912,000
WEC	\$380,179	\$62,405	\$442,584

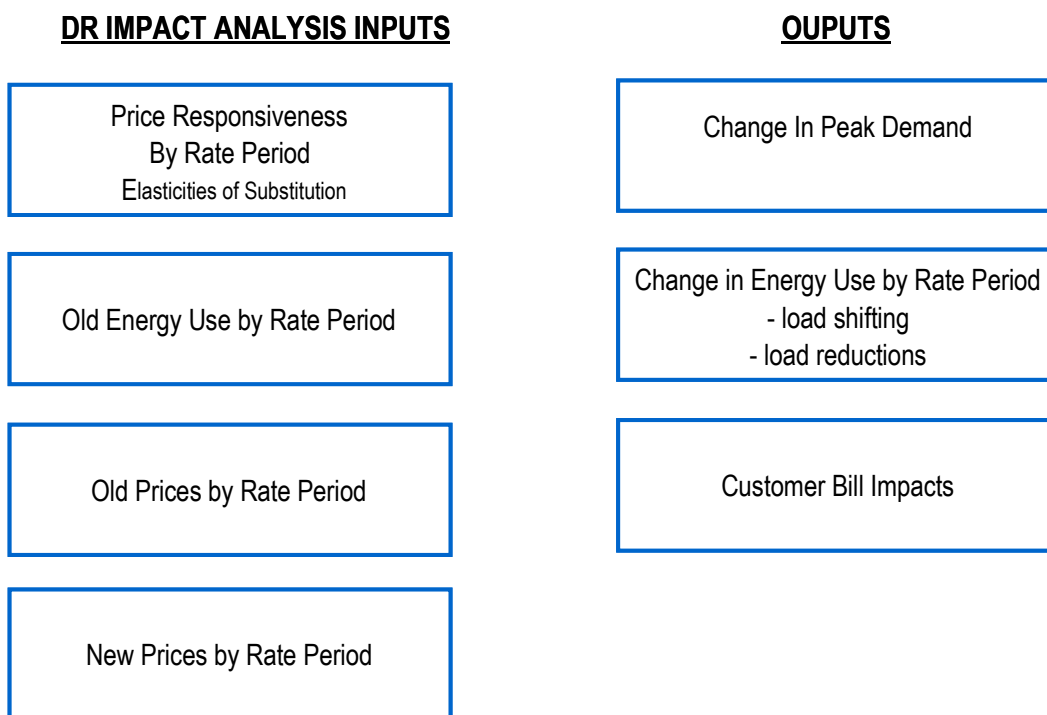
C.4. REMOTE CONNECT/DISCONNECT

As discussed in Section 4.3 of the main report, the potential benefits associated with remote connect/disconnect functionality was estimated for BED, where the relatively high degree of customer turnover experienced by that utility. Considering the scale of meter purchases, remote connect/disconnect equipment was assumed to amount to \$50 per meter and require \$0.75 in maintenance costs per meter-year. Two separate scenarios were modeled. The first assumed that all BED meters included remote connect/disconnect capability, resulting in \$60,000 of avoided labor and overhead costs per year. The second scenario assumed that 40% of meters (7,579) had remote connect/disconnect capability, resulting in \$45,000 of avoided labor and overhead costs per year. Forty percent of meters were targeted because this equals the share of multi-family housing units in BED territory. The labor escalation rate of 3.5% was applied to avoided remote connect/disconnect costs over the course of the analysis time period.

APPENDIX D. DEMAND RESPONSE IMPACT ANALYSIS

This appendix documents the inputs and assumptions underlying the estimation of load impacts resulting from time-based pricing given Vermont's customer characteristics, weather, and electricity prices. The change in average demand and annual energy usage due to time varying rates was estimated using FSC's rate design model, which can accommodate a variety of time varying rates and designs. Figure D-1 describes the main inputs and outputs of the model.

Figure D-1
Main Inputs and Outputs of FSC Rate Impact Model



The remainder of this appendix details the analysis and inputs used for designing time varying rates and for estimating the impact they have on average demand by rate period and on average annual energy consumption. Specifically, the appendix documents:

- The number of customers included in the analysis
- The selection of rate blocks
- The load shapes underlying the analysis and how they were customized for individual utilities
- The annual energy use per customer for each utility
- Price elasticities

- Prices (both current and time-varying)
- Calculation of the magnitude of the peak time rebate (or time-varying price differential by rate period)
- DR impact results
- Participation rates.

D.1. NUMBER OF CUSTOMERS INCLUDED IN THE ANALYSIS

Not all customers were included in the DR benefit analysis. As discussed in Section 4.1 of the main report, 10 small utilities were excluded from both the cost and benefit analysis based primarily on the assessment that it would be difficult to obtain any operational savings from AMI deployment for these utilities. Thus, the roughly 15,000 customers associated with the 10 excluded utilities were not included in the DR analysis.

Among the 10 utilities for which the analysis was conducted, both small and large C&I customers were excluded for reasons explained below. In addition, although customers with separately metered off-peak water heating were included in the analysis, the load associated with off-peak water heating was not included in the DR benefit analysis, as it was assumed that this load is already controlled during the peak period and, thus, no additional benefits could be obtained from time-based pricing.

C&I customers with estimated demands below 10 kW were excluded based on analysis from California's Statewide Pricing Pilot indicating that these customers, on average, do not respond to time-based pricing in the absence of enabling technology such as programmable communicating thermostats (PCTs). This analysis was summarized in Section 2.3 of the main report.

C&I customers with estimated demands above 200 kW were excluded from the analysis primarily because it is not necessary to install AMI to cost-effectively capture DR benefits from this segment. Typically, the demand benefits from this group of customers can be cost-effectively achieved using interval meters read remotely via telephone lines. In addition, many of these customers already have interval or TOU meters.

Identifying customers below the 10 kW and greater than 200 kW thresholds required some analysis, since the tariffs used by each utility in Vermont do not typically coincide with these thresholds. The relevant customers were identified using data from Efficiency Vermont, which includes usage data for almost all Vermont customers. The Efficiency Vermont database includes data on total kWh and, when relevant, peak and off-peak usage (kWh), demand (kW) readings, and power factors. The dataset was employed to calculate the number of customers, by tariff, that fit the profile of the targeted C&I customers. Not all utilities have demand readings for all their commercial and industrial customers. For those utilities, thresholds of 20,000 and 500,000 kWh were used as proxies for the below 10 kW and greater than 200 kW segments, respectively. Finally, the Efficiency Vermont billing data did not include BED. The BED tariff sheet, however, indicated that their small general service customers were generally lower than the 10 kW threshold. As a result, only the

Large General Service customers were included in the BED analysis. Table D-1 shows the breakdown of customers included and excluded for each utility.

Table D-1
Comparison of Customer Included in the DR analysis to Overall Customers

	Sector	Statistic	BED	CVPS	GMP	VEC	WEC	Smaller utilities	TOTAL
Included in DR analysis	<i>Residential</i>	# of Customers	16,197	131,483	78,240	33,217	9,917	17,698	286,752
		Annual Consumption GWh	91.2	911.0	582.3	242.4	61.8	112.2	2,000.8
	<i>C&I</i>	# of Customers	819	5,799	4,796	834	12	1,605	13,865
		Annual Consumption GWh	189.9	483.4	336.6	71.7	2.5	73.0	1,157.2
	<i>Total</i>	# of Customers	17,016	137,282	83,036	34,051	9,929	19,303	300,617
		Annual Consumption GWh	281.1	1,394.4	918.9	314.1	64.3	185.2	3,158.0
All customers	<i>Residential</i>	# of Customers	16,197	131,483	78,367	36,256	9,917	30,589	302,809
		Annual Consumption GWh	91.2	959.5	582.3	242.4	61.8	203.4	2,140.5
	<i>C&I</i>	# of Customers	3,657	21,541	14,031	3,009	266	4,553	47,057
		Annual Consumption GWh	264.4	1,318.9	1,374.6	217.9	6.7	431.5	3,614.1
	<i>Total</i>	# of Customers	19,854	153,024	92,398	39,265	10,183	35,142	349,866
		Annual Consumption GWh	355.6	2,278.3	1,956.9	460.2	68.5	634.9	5,754.6

Source: Company Annual Reports and Data Request Responses

Within the group of C&I customers between 10 and 200 kW, there were often multiple tariffs. Since, DR benefits are based on a comparison of the current average price with the average price under a time-varying tariff, it was useful to divide the target segment into multiple tariff categories in some cases. Given this, the DR analysis generally included two commercial rates per utility: Commercial Rate #1 represents customers in the lower end of the 10kW to 200kW range, and Commercial Rate #2 represents customers in the upper end of the 10kW-200kW range. Table D-2 shows the breakdown of the C&I customer population into the R1 and R2 categories.

Table D-2
C&I Customers by Rate Class

Utility	Commercial Rate #1		Commercial Rate #2	
	Customers	Avg. Annual Usage (kWh)	Customers	Avg. Annual Usage (kWh)
BED	DNA	DNA	819	231,892
CVPS	5,039	48,759	760	312,808
GMP	3,182	36,217	1,265	175,000
WEC	DNA	DNA	12	210,938
Smaller utilities	1,070	21,384	535	93,693
TOTAL	9,291	41,311	3,391	206,926

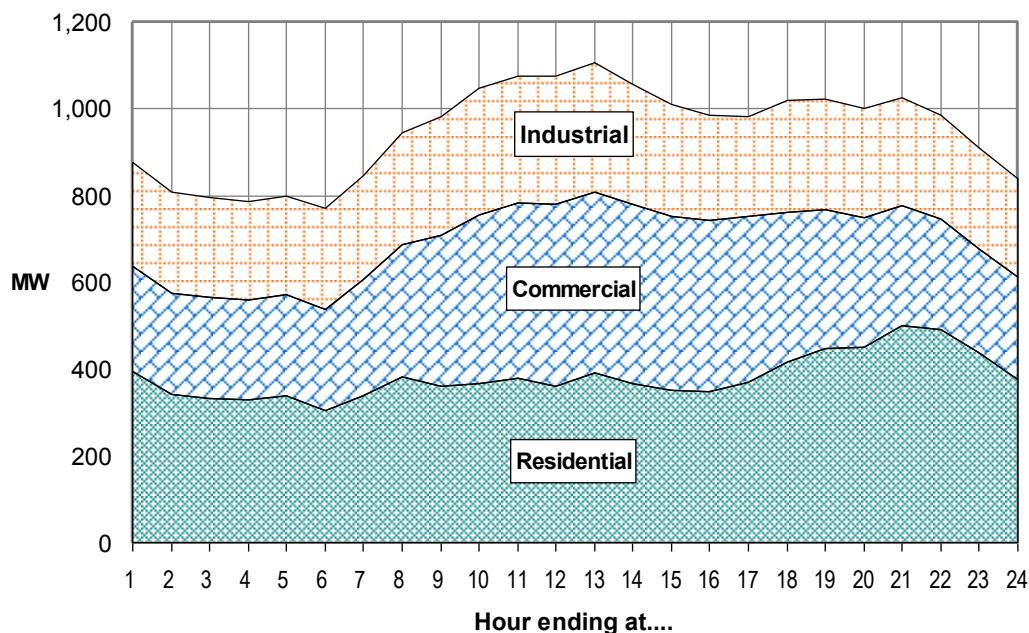
D.2. LOAD SHAPES UNDERLYING THE ANALYSIS

In order to estimate DR benefits, it is necessary to have initial estimates and average use by customer segment and rate period. For dynamic rates such as CPP and PTR, estimates of load during the peak and off-peak periods is needed for days that are representative of when critical events are likely to be called. In order to estimate impacts for a variety of rate and day types, it is essential to have hourly load data for relevant customer segments.

In Vermont, the only utility that had useful load research data for relevant customer segments was BED, which had load data for representative samples of customers for 2004 and 2005. VEC had some potentially useful load data on customers based on their partial deployment of advanced meters, but the data was not available in time nor had it undergone sufficient quality control procedures to be used for this analysis. Thus, the BED load shapes were used for all utilities. A normalized load shape was developed from the BED data and then applied to the annual usage data that represents each utilities customer base. Put another way, only the BED pattern of usage was used for the other utilities, not the overall load annual energy use.

To crosscheck the validity of applying BED data for Vermont, the Vermont load during the 2006 ISO-NE system peak day was compared with estimates of the system peak constructed using the customized BED load data. Figure D-2 describes the estimates of customer class contribution to Vermont load on the 2006 ISO-NE system peak day based on the normalized BED load shapes.

Figure D-2
Statewide Load by Class on ISO-NE 2006 System Peak
Estimates based on normalized load shapes, VT total customers by class, and average annual kWh



Two points should be noted:

1. The BED 2006 system peak day load shapes lead to slightly higher load estimates than the ISO-NE readings for Vermont after taking into account utility-specific annual usage and number of customers. The Vermont load at the time of ISO-NE system peak was 1,032 MW. The statewide estimate based on the BED August 2nd load shapes (without calibration) is 1,057 MW – 2.4% higher. The BED estimates are slightly higher than the ISO-NE readings throughout the day.
2. The residential sector peaks at a different hour than the ISO-NE system. Residential load peaks between 21:00 and 22:00, and the ISO-NE peaked between 13:00 and 14:00. The residential class peak is roughly 500 MW, but at the time of system peak, residential load was roughly 350 MW.

Importantly, as is discussed further in the next section, the base critical day energy use estimates are based on the average hourly demand across the 20 days (for each year) with the highest ISO-NE system load, leading to conservative estimates that more than correct any upward bias in using the BED load shapes. The critical day load shapes produce estimates 15 to 25 percent lower than relying solely on the system peak load shapes. Figures D-3 and D-4 compare the BED load shape for the 2006 system peak with the load shapes employed for critical days for residential and large commercial customers.

Figure D-3
Residential August 2nd Load v. Average Load across Top 20 summer days

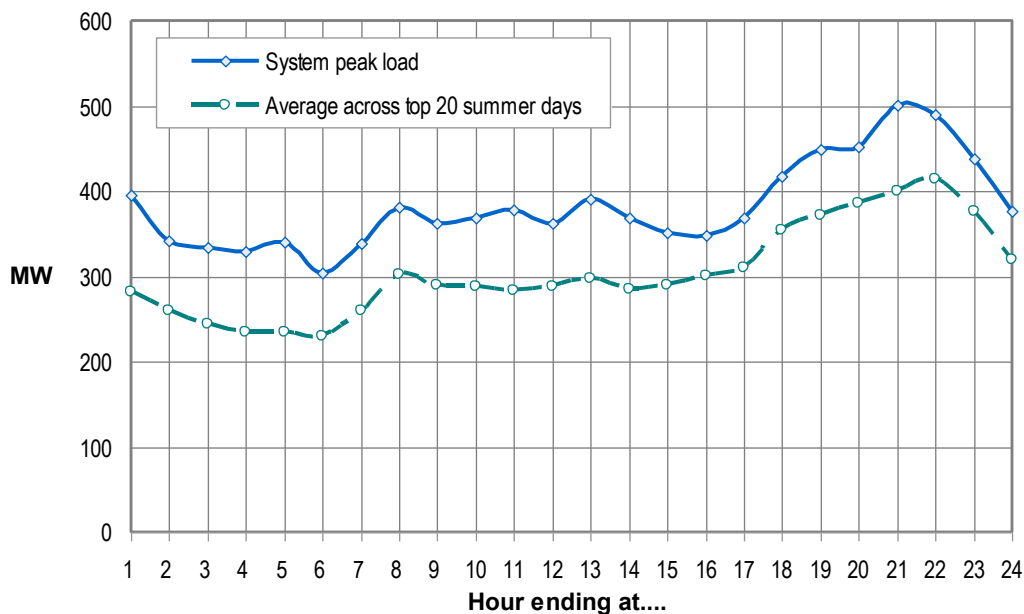
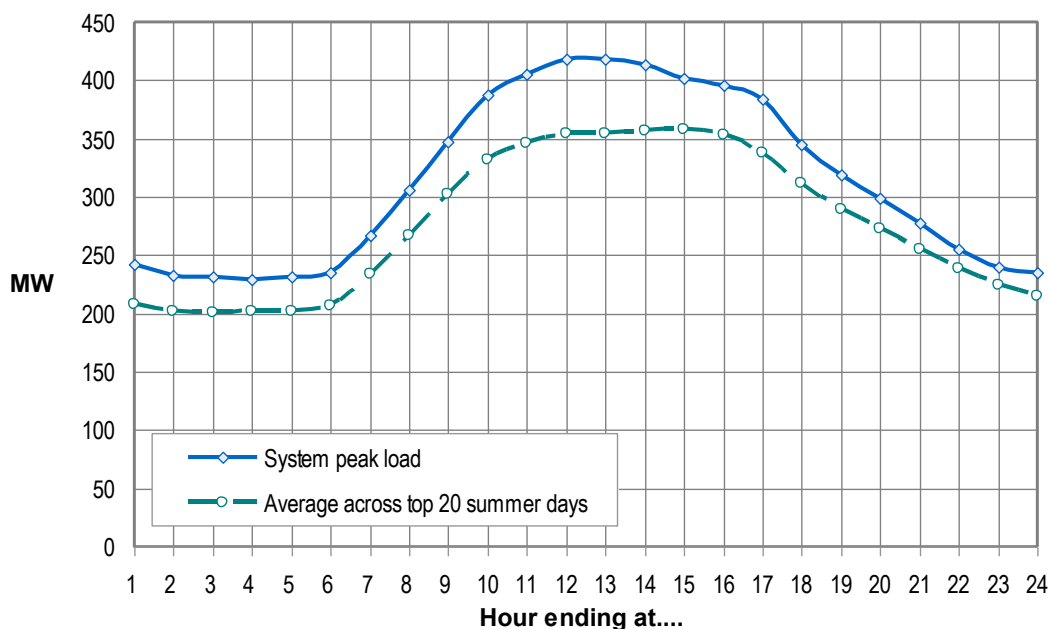


Figure D-4
Commercial August 2nd Load v. Average Load across Top 20 summer days



D.3. ANNUAL ENERGY USE BY UTILITY AND RATE CLASS

In order to estimate the kW demand reductions for each utility, estimates of average hourly demand in the absence of DR were required for PTR event and non-event days for the peak and off-peak periods. These base hourly demand estimates were combined with estimates of price responsiveness to calculate the average hourly demand with the time-varying rate in place.

Usage estimates by time period for a typical PTR day were based on the top 20 system load days for 2005 and 2006, even though the DR benefit estimates assume only 12 event days will be used on average each year. The average hourly demand across the top 20 days was used because it is a more conservative estimate than using the top 12 system load days. Importantly, as Figures D-3 and D-4 showed, the average hourly demand across the 20 days with the highest ISO load is substantially lower than the average hourly demand during the system peak day.

The peak period is noon to 6 pm, which captures the time of typical ISO-NE system peaks. The peak period was selected after an analysis of:

- ISO-NE load shapes for the 40 highest peak load days for each summer from the years 2003-2007
- Vermont load shapes for the 40 highest peak load days for each summer from 2003-2007

- The ISO-NE historical record of OP4 events and the zones that were called upon during emergency conditions
- The coincidence of high ISO-NE system loads and high Vermont system loads
- The coincidence of the ISO-NE weighted temperatures and the Vermont temperatures

Tables D-3, D-4, and D-5 contain estimates of the starting average hourly demand by time period and by utility for residential and commercial customer (Rate #1 and Rate #2) prior to any change in behavior induced by time-based pricing. These initial estimates are projected to change over time according to the growth or contraction in average annual energy use and peak demand (system coincident) detailed in Appendix G.

Table D-3
Residential Customers: Average Hourly Demand by Rate Period and Utility w/o DR

SEASON	DAY TYPE	Rate period	BED	CVPS	GMP	VEC	WEC	Smaller Utilities
Summer	Critical Day	Peak (12-6 pm)	0.79	0.98	1.04	0.94	0.88	0.89
		Off-peak	0.78	0.95	1.02	0.92	0.86	0.87
	Weekday	Peak (12-6 pm)	0.63	0.78	0.83	0.75	0.70	0.71
		Off-peak	0.63	0.78	0.83	0.75	0.70	0.71
	Weekend	Peak (12-6 pm)	0.72	0.89	0.95	0.86	0.80	0.82
		Off-peak	0.64	0.79	0.84	0.76	0.71	0.72
Non-Summer	Critical Day	Peak (12-6 pm)	-	-	-	-	-	-
		Off-peak	-	-	-	-	-	-
	Weekday	Peak (12-6 pm)	0.62	0.77	0.82	0.74	0.69	0.70
		Off-peak	0.62	0.76	0.81	0.73	0.68	0.70
	Weekend	Peak (12-6 pm)	0.75	0.92	0.98	0.89	0.83	0.84
		Off-peak	0.63	0.78	0.83	0.75	0.70	0.71

Table D-4
Commercial Rate #1: Average Hourly Demand by Rate Period and by Utility w/o DR

SEASON	DAY TYPE	Rate period	BED	CVPS	GMP	VEC	WEC	Smaller Utilities
Summer	Critical Day	Peak (12-6 pm)		10.95	8.13	14.77		4.80
		Off-peak		6.29	4.67	8.49		2.76
	Weekday	Peak (12-6 pm)		9.57	7.11	12.91		4.20
		Off-peak		5.36	3.98	7.23		2.35
	Weekend	Peak (12-6 pm)		5.44	4.04	7.34		2.39
		Off-peak		4.05	3.01	5.47		1.78
Non-Summer	Critical Day	Peak (12-6 pm)	-		-	-		-
		Off-peak	-		-	-		-
	Weekday	Peak (12-6 pm)		8.09	6.01	10.91		3.55
		Off-peak		5.18	3.85	6.99		2.27
	Weekend	Peak (12-6 pm)		4.80	3.57	6.47		2.11
		Off-peak		4.18	3.10	5.64		1.83

Table D-5
Commercial Rate #2: Average Hourly Demand by Rate Period and by Utility w/o DR

SEASON	DAY TYPE	Rate period	BED	CVPS	GMP	VEC	WEC	Smaller Utilities
Summer	CPP	Peak (12-6 pm)	40.13	54.13	30.28	27.96	36.50	16.21
		Off-peak	29.45	39.73	22.23	20.52	26.79	11.90
	Weekday	Peak (12-6 pm)	37.22	50.20	28.09	25.93	33.85	15.04
		Off-peak	26.96	36.36	20.34	18.78	24.52	10.89
	Weekend	Peak (12-6 pm)	28.88	38.95	21.79	20.12	26.27	11.67
		Off-peak	23.47	31.66	17.71	16.36	21.35	9.48
	CPP	Peak (12-6 pm)	-	-	-	-	-	-
		Off-peak	-	-	-	-	-	-
	Weekday	Peak (12-6 pm)	33.22	44.81	25.07	23.15	30.22	13.42
		Off-peak	25.28	34.10	19.08	17.61	22.99	10.21
Non-Summer	Weekend	Peak (12-6 pm)	25.38	34.24	19.16	17.69	23.09	10.26
		Off-peak	21.50	29.00	16.22	14.98	19.55	8.69

D.4. PRICE ELASTICITIES

The change in energy use during peak periods on PTR days is based on estimates of the elasticity of substitution and daily price elasticities from California's Statewide Pricing Pilot (SPP) taking into consideration differences in climate and air conditioning patterns between California and Vermont.⁷ The SPP included participants from a variety of climate regions, a wide range of air conditioning penetration and substantial regional variation in annual energy consumption. Importantly, the SPP models allow the elasticity values for residential customers to be adjusted based on differences in climate and central air conditioning saturations.

Elasticities are simply measures of customer responsiveness to implicit or explicit changes in electricity prices. The elasticity of substitution reflects load shifting by customers and can

⁷ The residential elasticity estimates are documented in CRA International, *Impact Evaluation of California's Statewide Pricing Pilot*. Final Report, March 16, 2005. The C&I elasticity estimates are documented in Stephen S. George, Ahmad Faruqui and John Winfield, *California's Statewide Pricing Pilot: Commercial & Industrial Analysis Update*. Final Report, June 28, 2006. Both reports can be accessed at <http://www.energy.ca.gov/demandresponse/documents/index.html#group3>.

be used to estimate the change in the ratio of peak to off-peak energy use as a function of the ratio of peak to off-peak prices. The daily price elasticity can be used to estimate the change in daily energy use as a function of the change in average daily prices. In combination, the two values can be used to predict the change in energy use and average hourly demand for each rate period and overall. Importantly, the elasticities employed reflect the average price responsiveness across customers and are not meant to describe how individual customers would respond to changes in the price signal.

Table D-6 provides a summary of the commercial and residential elasticities employed in the base analysis scenario.

Table D-6
Summer Elasticities by Sector

Day Type	Type of Elasticity	Commercial	Residential
<i>Event Day</i>	Substitution	-0.0412	-0.0497
	Daily price	-0.0250	-0.0350
<i>Weekdays</i>	Substitution	-0.0493	-0.0431
	Daily price	-0.0250	-0.0389
<i>Weekends & Holidays</i>	Daily price	-0.0250	-0.0383

Basing the Vermont price elasticities on the California Statewide Pricing Pilot inherently raises the question of the applicability of the SPP elasticities to Vermont. Several points are worth highlighting:

- The estimates of customer load responsiveness used in this study were based on the California Statewide Pricing Pilot but customized for Vermont using the Vermont air conditioning penetration and weather, the two main factors that affect residential responsiveness. The impact is not presumed to be the same as in California.
- The California Pricing Pilot encompassed a variety of climate zones and customers in all of the climate zones provided load response, including customers in coastal areas with summers cooler than Vermont and virtually no air conditioning.
- As indicated in the discussion in Section 2.3, and in Figure 2-1, a number of other pricing pilots have found similar levels of demand response to those observed in the SPP, in spite significant differences in population characteristics.
- California, like Vermont, has had decades of experience with energy efficiency and has been targeting the energy efficiency programs at loads coincident with system peak.

- Energy use per household is low relative to the rest of the U.S. for both California and Vermont. In fact, they are the only two states where per capita energy use has remained flat over the last few decades.
- The load responsiveness estimates were held constant over the entire analysis period, even though all indicators point to increased air conditioning penetration which, in turn, would likely increase price responsiveness. As such, the demand reduction estimate may be conservative.

D.4.1. Residential Sector Price Responsiveness

For the residential sector analysis, the load reduction estimates are based on elasticities derived from the SPP, tailored to reflect the weather conditions and air conditioning saturation in Vermont. The following steps were used to estimate the Vermont elasticities:

- Identify the share of homes with central air conditioning or three or more room air conditioners based on statewide survey data saturation survey.
- Calculate the average weather by rate period, in terms of average cooling degrees per hour using a base of 72° F.
- Customize the elasticity of substitution and daily price elasticities the SPP model and Vermont air conditioning penetration and weather

A key driver of demand response is air conditioning saturation. In the California pricing experiment, homes with air conditioning typically had central air conditioning and provided substantially larger load reductions than households without central air conditioning. In Vermont, households with air conditioning typically have room air conditioners instead of central air conditioning. In total, 4% of the homes in Vermont have central air conditioning and an additional 15.5% have multiple room air conditioners.⁸ Moreover, the penetration and saturation of room air conditioners has been growing over the last decade and is expected to continue growing over the forecast horizon. Because of the differences in the type of air conditioning equipment, the 3.2% of homes in Vermont with three or more room air conditioners were treated as equivalent to a central air conditioner in order to create tailored elasticity estimates for Vermont.⁹ The sensitivity of DR impact estimates to variation in air conditioning saturation is shown at the end of this section.

Table D-7 show the average cooling degrees per hour, with a base of 72 degrees, for the rate blocks employed in the analysis. The averages were calculated by using the ISO-NE's 2003-2007 Vermont zone data, which includes weather data.

⁸ Kema (2005). Final Report: Phase 2 Evaluation of the Efficiency Vermont Residential Programs, p. 3-10

⁹ The share of homes with three or more room air conditioners was based on the RASS BED sub-sample. BED was the only utility that provided detailed frequencies, enabling identification of the share of households with three or more room air-conditioners. The estimate is likely an undercount of Vermont homes with three or more room air conditioners given that the share of homes with multiple room A/C units is lower for BED (13.2%) than for the rest of the state (15.5%).

Table D-7
Vermont Summer Average Cooling Degrees per Hour by Day Type

Day Type	Peak		Off-peak		Daily	
	Avg. Temperature	Avg. CDH/hr	Avg. Temperature	Avg. CDH/hr	Avg. Temperature	Avg. CDH/hr
Event Days	81.26	9.61	72.68	2.96	74.82	4.62
Weekdays	74.01	3.87	64.86	0.76	67.15	1.54
Weekends & Holidays	74.38	4.65	65.77	1.06	67.96	1.95

* Average cooling degree hours are not the same as the average temperature minus the base

The elasticity of substitution was customized for Vermont using the Vermont air conditioning penetration and weather and the SPP models as described below. Equation D-1 provides the SPP regression model specification used to calculate customer load shifting from peak to off-periods in response to price signals.

Equation D-1

$$\ln\left(\frac{Q_p}{Q_{op}}\right) = \alpha + \sum_{i=1}^N \theta_i D_i + \sigma \ln\left(\frac{P_p}{P_{op}}\right) + \delta(CDH_p - CDH_{op}) + \lambda(CDH_p - CDH_{op}) \ln\left(\frac{P_p}{P_{op}}\right) + \phi(CAC) \ln\left(\frac{P_p}{P_{op}}\right) + \varepsilon$$

were:

Q_p = average energy use per hour in the peak period for the average day

Q_{op} = average energy use per hour in the off-peak period for the average day

σ = the elasticity of substitution between peak and off-peak energy use (defined below)

P_p = average price during the peak pricing period

P_{op} = average price during the off-peak pricing period

δ = measure of weather sensitivity

CDH_p = cooling degree hours per hour during the peak pricing period²⁸

CDH_{op} = cooling degree hours per hour during the off-peak pricing period

θ_i = fixed effect coefficient for customer i

D_i = a binary variable equal to 1 for the i^{th} customer, 0 otherwise, where there are a total of N customers.

ε = regression error term

Equation D-1 estimates load shifts from peak to off-peak periods as a function of changes in peak to off peak price ratio, air conditioning, and temperature. The price term is interacted with central air conditioning and weather, meaning that the elasticity estimate is a composite of three terms. The composite elasticity of substitution in this model is a function of the three terms shown in equation D-2. The model parameters were drawn from Appendix 16-C of the SPP report (p. 147-151).

Equation D-2

$$ES = \sigma + \lambda(CDH_p - CDH_{op}) + \phi(CAC)$$

Inserting the Vermont values for air conditioning penetration and weather into equation D-2 produces the Vermont specific elasticity of substitution values of -0.0497 and -0.0431 for event days and weekdays, respectively.

The residential daily price elasticities were also customized for Vermont using the Vermont air conditioning penetration, Vermont weather, and SPP models. Equation D-3 provides the SPP regression model specifications used to calculate customer load reductions during event days in response to price signals.

Equation D-3

$$\ln(Q_D) = \alpha + \sum_{i=1}^N \theta_i D_i + \eta \ln(P_D) + \rho(CDH_D) + \chi(CDH_D) \ln(P_D) + \xi(CAC) \ln(P_D) + \varepsilon$$

were:

Q_D = average daily energy use per hour

η = the daily price elasticity

P_D = average daily price

ρ = measure of weather sensitivity

χ = the change in daily price elasticity due to weather sensitivity

CDH_D = average daily cooling degree hours per hour (base 72 degrees)

ξ = the change in daily price elasticity due to the presence of central air conditioning

CAC = 1 if a household owns a central air conditioner, 0 otherwise

θ_i = fixed effect for customer i

D_i = a binary variable equal to 1 for the i^{th} customer, 0 otherwise, where there are a total of N customers.

ε = regression error term.

Equation D-3 estimates the average hourly load during the event day as a function of the average daily price, air conditioning, and average daily temperature. As with the elasticity of substitution model, the price term is interacted with central air conditioning and weather, meaning the that the elasticity estimate is a composite of three terms. The composite

elasticity of substitution in this model is the function of the three terms shown in equation D-4. The model parameters were drawn from Appendix 16-C of the SPP report (p. 147-151).

Equation D-4

$$\text{Daily} = \eta + \chi(CDH_d) + \xi(CAC)$$

Inserting the Vermont values of air conditioning penetration and weather into equation D-4 produces the Vermont specific daily prices elasticities of -0.0350, -0.0389, and -0.0383 for event days, weekdays, and weekends, respectively.

D.4.2. C&I Sector Price Responsiveness

The SPP analysis also estimated price elasticities for C&I customers. These estimates do not vary with climate or customer characteristics other than size. Elasticity values were estimated for two customer segments in the SPP, one for customers with peak demands below 20 kW and one for customers with peak demands between 20 and 200 kW. Elasticity values estimated from the SPP pilot also varied for customers with and without programmable communicating thermostats (PCTs). For the small customer segment, there was no statistically significant price response unless PCTs were present. Larger customers were price responsive with and without PCTs present, but the elasticity estimates were larger given the presence of a PCT.

As previously discussed, we excluded the smallest customers from this analysis based on the above finding that they were not price responsive unless PCTs were present. For the medium general service customers, we used the non-PCT enabled elasticity of substitution estimate for the 20 to 200 kW customer segment from the SPP (-0.041).

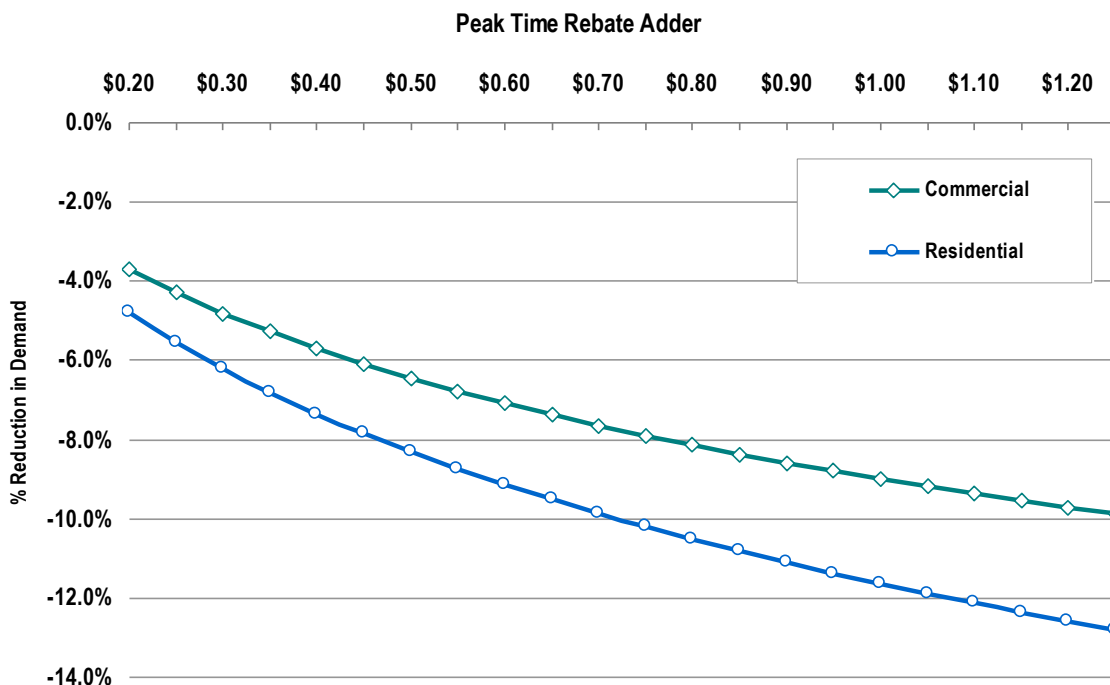
In the SPP analysis, price was not statistically significant in the daily energy use equations for C&I customers. This lack of statistical significance does not necessarily mean that price doesn't influence daily energy use, only that this influence could not be estimated with sufficient precision based on the relatively small SPP sample sizes. There is much less variation in daily price across day types and treatment cells than there is in the price ratio, which would explain why it is possible to develop estimates of the elasticity of substitution but not the daily price elasticity. It is reasonable to expect that there would be some responsiveness to daily price variation, as a zero daily price elasticity combined with a negative and significant value for the elasticity of substitution would imply that the amount of energy reduced in the peak period would be exactly offset by an increase in energy use in the off-peak period. Since most load in the C&I sector is due to air conditioning and lighting, and these end uses are difficult to shift from one time period to another, we felt that it was appropriate to assume some small value for the daily price elasticity. A survey of the literature by Bohi¹⁰ reported a range in estimates of the daily price elasticity from -0.05 to -0.20. To be conservative, we assumed a value of -0.025, which equals half of the low end of the range reported by Bohi.

¹⁰ Bohi, D.R. *Analyzing Demand Behavior*. Baltimore: Johns Hopkins University Press, 1981.

D.4.3. Sensitivity Analysis: Customer Responsiveness to Peak Time Rebates

The overall change in average hourly demand is a function of the base energy usage, the customer price responsiveness (elasticities), and the change in prices. Figure D-6 presents the load reduction estimates at various PTR levels using the substitution and daily price elasticities reported above, assuming a base rate of 12 cents per kWh.

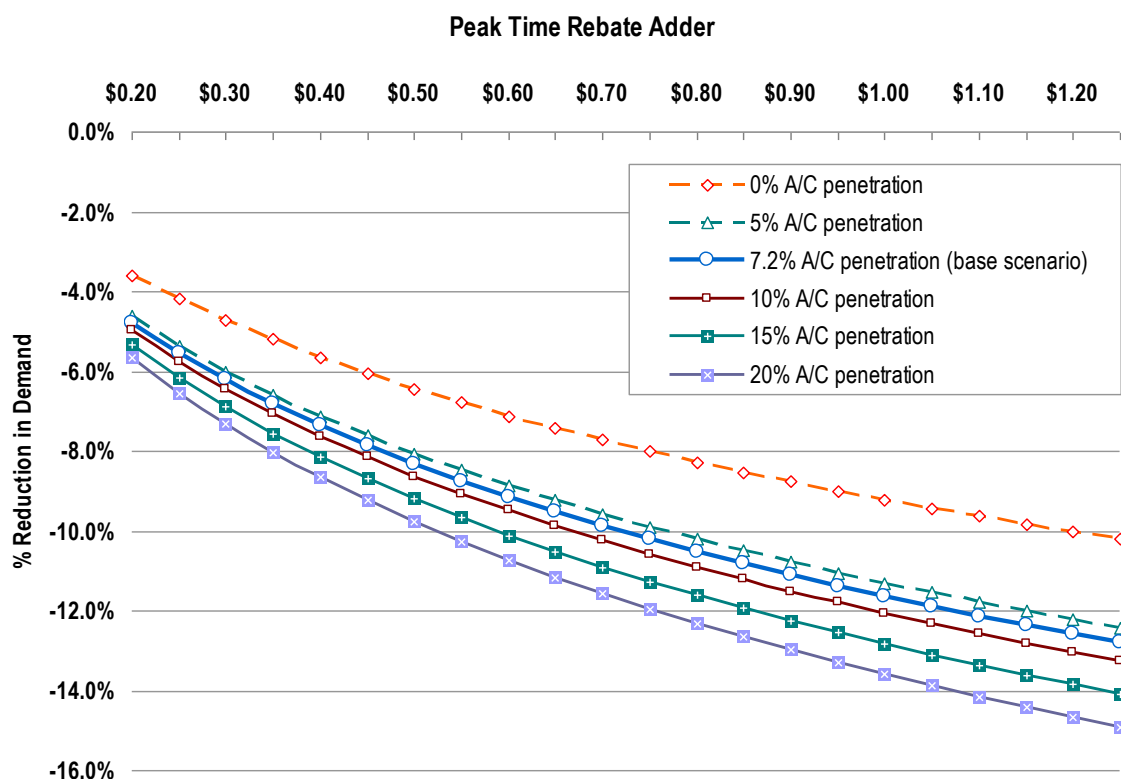
Figure D-6
Percent Load Reduction During Event Days by Rate Class and Peak Time Rebate
Based on Elasticities Employed in Analysis and 12 cent Base Rate



The chart highlights three important points. First, the average percent load reduction depends on both the change in peak to off-peak price ratio from the old prices to the new prices. The above chart uses a 12 cent per kWh base rate in order to illustrate percent impacts, but in practice the impact varied by individual utilities based on their current tariffs. Second, the impact of higher rebates is non-linear – i.e., the initial fifty cents of peak time rebate results in more incremental load response than the second fifty cents. Third, peak time rebates can be adjusted to obtain more load response and more demand response benefits.

Figure D-7 presents sensitivity analysis showing how air conditioning penetration affects the residential percent average demand reduction during event days. The estimated saturation of 7.2 percent produces a 10 percent reduction in peak-period energy use on critical days, given a 75 cent per kWh peak time rebate. If it was assumed that there was no air conditioning at all, the reductions would be roughly 8 percent.

Figure D-7
Impact of A/C penetration on Residential Percent Load Reduction During Events Days
Based on 12 cent Base Rate



D.5. RETAIL PRICES (BASE AND TIME-VARYING)

The change in energy use by time period resulting from the peak time rebate incentive is based on the relationship between the average prices paid by customers prior to participating in the PTR program and the opportunity cost of not adjusting their usage. For example, if the incentive payment equals \$0.75/kWh and the average electricity cost is \$0.1200/kWh, the opportunity cost of not reducing usage by 1 kWh during the peak period on an event day is \$0.8700/kWh (the sum of the two prior numbers). In this example, the load impact reductions are based on the ratio of \$0.8700/kWh to \$0.1200/kWh, or roughly 7.25.

The average current prices for each utility, customer type, and rate block were computed based on the respective tariff sheets, average monthly usage, and average customer monthly peak demand, if applicable. Calculating average prices faced by customers requires not only applying Vermont charges per kWh, but also incorporating any pre-existing time-varying component (e.g., TOU) and demand charges, if applicable. In calculating the average prices, we did not include the monthly service charges since they are not affected by consumption or demand levels. In some cases, such as VEC, where several rates are available for residential and small and large commercial customers, a weighted average was employed. For the smaller utilities, the tariff sheets were not immediately available and even

if available would require significant effort to blend. As a result, the analysis for these utilities was based on the total kWh and revenue by sector, and an assumed average fixed charges of \$10/month for residential customers, and \$12/month and \$40/month for commercial customers at the lower and upper ends of 10kW to 200kW range, respectively.

Table D-8 presents the initial and new prices employed for residential customers. Tables D-9 and D-10 present the initial and new prices for commercial rates at the lower and upper ends of the target customer range (10kW-400kW), respectively. Table D-10 includes a more detailed breakdown showing the average price in each of the rate periods because it was necessary to incorporate both time varying usage and demand charges for the CVPS and GMP larger customers.

Table D-8
Average Price per kWh - Residential Customers

	Description	BED	CVPS	GMP	VEC	WEC	Smaller Utilities
Initial Prices	Avg Summer Price	\$0.1251	\$0.1194	\$0.1290	\$0.1432	\$0.1390	\$0.1228
	Avg Winter Price	\$0.1251	\$0.1195	\$0.1291	\$0.1485	\$0.1390	\$0.1228
	Fixed Monthly Charge	\$7.37	\$11.64	\$9.91	\$10.62	\$9.24	\$10.00
New Prices	CPP day peak price (1)	\$0.8751	\$0.8692	\$0.8789	\$0.8932	\$0.8890	\$0.8728
	Summer Off-peak (2)	\$0.1251	\$0.1192	\$0.1289	\$0.1432	\$0.1390	\$0.1228
	Non-summer peak (3)	\$0.1251	\$0.1198	\$0.1293	\$0.1485	\$0.1390	\$0.1228
	Non-summer off-peak (4)	\$0.1251	\$0.1194	\$0.1290	\$0.1485	\$0.1390	\$0.1228
	CPP / Summer off-peak price ratio (1/2)	7.00	7.29	6.82	6.24	6.39	7.11
1	BED include rates RS and RT						
2	CVPS includes rates 1 and 11						
3	GMP includes rates 1 and 11						
4	VEC includes residential rates 1, 2, 5, 6 and VRES						
5	WEC includes rates 1 and 2						

Table D-9
Average Price per kWh – Commercial Rate #1

	Description	BED	CVPS	GMP	VEC	WEC	Smaller Utilities
Initial Prices	Avg Summer Price		\$0.1455	\$0.1214	\$0.1103		\$0.1310
	Avg Winter Price		\$0.1461	\$0.1214	\$0.1237		\$0.1310
	Fixed Monthly Charge		\$13.96	\$16.41	\$15.61		\$12.00
New Prices	CPP day peak price (1)		\$0.8955	\$0.8714	\$0.8603		\$0.8810
	Summer Off-peak (2)		\$0.1455	\$0.1214	\$0.1103		\$0.1310
	Non-summer peak (3)		\$0.1461	\$0.1214	\$0.1237		\$0.1310
	Non-summer off-peak (4)		\$0.1461	\$0.1214	\$0.1237		\$0.1310
	CPP / Summer off-peak price ratio (1/2)		6.16	7.18	7.80		6.73

- 1 BED did not provide Efficiency Vermont billing data to determine the number of customers in the 10kW to 200 kW range. However, the tariff description made it clear that small general service customers were likely outside the target customer size.
- 2 CVPS includes rate 2 customer with peak demand charges
- 3 GMP includes rates 6 and 21
- 4 VEC includes residential rates 1, 2, 5, 6 and VRES

Table D-10
Average Price per kWh – Commercial Rate #2

Average Price per kWh - Commercial Rate #2									
SEASON		DAY TYPE	Rate period	BED	CVPS	GMP	VEC	WEC	Smaller Utilities
Initial Prices	Summer	Event Day	Peak	\$0.1159	\$0.1444	\$0.1461	\$0.1200	\$0.1180	\$0.1277
			Off-peak	\$0.1159	\$0.1243	\$0.1203	\$0.1200	\$0.1180	\$0.1277
		Weekday	Peak	\$0.1159	\$0.1450	\$0.1469	\$0.1200	\$0.1180	\$0.1277
			Off-peak	\$0.1159	\$0.1250	\$0.1211	\$0.1200	\$0.1180	\$0.1277
		Weekend	Peak	\$0.1159	\$0.1449	\$0.0650	\$0.1200	\$0.1180	\$0.1277
			Off-peak	\$0.1159	\$0.1225	\$0.0649	\$0.1200	\$0.1180	\$0.1277
	Non-Summer	Weekday	Peak	\$0.1124	\$0.1475	\$0.1488	\$0.1210	\$0.1111	\$0.1277
			Off-peak	\$0.1124	\$0.1266	\$0.1223	\$0.1210	\$0.1111	\$0.1277
Weekend		Peak	\$0.1124	\$0.1474	\$0.0646	\$0.1210	\$0.1111	\$0.1277	
		Off-peak	\$0.1124	\$0.1240	\$0.0645	\$0.1210	\$0.1111	\$0.1277	
New Prices	Event day peak price (1)			\$0.8659	\$0.8743	\$0.8703	\$0.8700	\$0.8680	\$0.8777
	Summer peak price (2)			\$0.1159	\$0.1449	\$0.1233	\$0.1200	\$0.1180	\$0.1277
	Summer Off-peak (3)			\$0.1159	\$0.1243	\$0.1203	\$0.1200	\$0.1180	\$0.1277
	Non-summer peak (4)			\$0.1124	\$0.1475	\$0.1488	\$0.1210	\$0.1111	\$0.1277
	Non-summer off-peak (5)			\$0.1124	\$0.1266	\$0.1223	\$0.1210	\$0.1111	\$0.1277
	CPP / Summer off-peak price ratio			7.47	7.03	7.23	7.25	7.36	6.87

- 1 BED includes LGS rate
- 2 CVPS includes rates 10
- 3 GMP includes rates 65
- 4 VEC includes residential rates 7, 9, VCLCM, and PLCM
- 5 WEC includes rates 8

To calculate an average price per kWh the following steps were taken for the summer and non-summer periods¹¹:

1. Calculate the revenue/payment associated with electricity consumption (kWh) by time period:
 - a. For rates that varied by month/season, the calculation took into account the month-to-month variation in consumption from the billing data.
 - b. For rates that varied by time of day (for large customers), the usage by hour and season were multiplied by the appropriate kWh charge. In order to reflect usage, the normalized load shapes and average customer annual usage were employed.
2. Calculate the revenue/payment associated with demand charges (if demand charges apply) by time period
3. Calculate the revenue/payment associated with any other rate components such as power factors

¹¹ None of the customers included in the load impact and DR cost/benefit calculation faced time of use rates, which allowed the rates to be directly grouped into summer and non-summer periods.

4. Divide the revenue/payment (excluding fixed charges) for each of the PTR rate periods (under the initial rates) by the electricity usage (kWh) during each rate period, providing the weighted average price paid per kWh by rate period.

D.6. COST BASED PEAK REBATE CALCULATIONS

The incentive payment for each customer segment underlying the analysis equals \$0.75/kWh. Conceptually, this is based on the idea that utilities should be willing to pay up to the avoided cost of capacity to reduce usage during times when capacity costs are incurred. The \$0.75/kWh value is significantly less than the full avoided capacity cost as indicated in the following analysis.

If no peak time rebates were offered and customers continued their current usage patterns, the utility would have higher capacity costs because of higher allocation of capacity costs (based on its contribution to system peak) and a higher installed capacity requirement (due to the higher overall system peak). The total revenue associated with capacity can be estimated by multiplying the average on-peak load for the customer segment on the top 100 system hours by the capacity value. The analysis in Table D-11 uses the market equilibrium capacity values as estimated by the ISO-NE, since it is reasonable to conclude that the market will tend toward equilibrium. This value is better known as the cost of new entry (CONE) and represents the fixed operating costs and capital costs of a peaking unit (this can be thought of as the cost of having the peaking unit or capacity available).

Dividing the revenue requirement associated with capacity by the energy usage during those hours provides the capacity costs avoided per kWh reduced. Based on this analysis, the maximum cost based peak time rebate is approximately \$1.25/kWh for Vermont. As indicated above, we used a more conservative value of \$0.75/kWh for the peak time rebate.

Table D-11
Cost Based Peak Time Rebate Calculations

Line	Description	Units	Value	Notes
1	Average on-peak load during the 20 days with highest system load	MW	556.2	Average customer load X number of customers
2	Equilibrium marginal capacity cost	\$/kW-year	\$90.00	ISO-NE value for cost of new entry (7.50/month X 12)
3	Marginal Cost Revenues required for capacity	\$	\$50,058,000	Line 1 X Line 2 x 1,000
4	Energy usage during on-peak critical day periods	kWh	40,046,400	Average customer load X number of customers X event days X on-peak hours
5	Maximum cost based PTR credit	Cents/kWh	125.0	Line 3/Line 4
6	Illustrative AMI PTR credit	Cents/kWh	75.0	

D.7. DR IMPACTS PER CUSTOMER

The average load impacts per customer are a function of the initial average hourly demand, customer responsiveness (in the form of load shifting and consumption reductions), and the initial and new prices. Higher initial average hourly loads and higher price responsiveness lead to larger load impacts per customer. In contrast, higher initial prices are associated with slightly lower load impacts due to the smaller peak to off-peak price ratio.

Tables D-12, D-13, and D-14 summarize the starting average demand, energy, and billing impacts of a 75 cent peak time rebate for the customers included in the demand response analysis. The impacts grow or shrink in tandem with critical peak growth and energy use per capita. Tables D-15, D-16, and D-17 provide the impacts for alternative peak time rebates.

Table D-12
Base Peak Time Rebate (75c) Average Residential Customer
Demand, Energy, and Billing Impacts (Starting Values)

Result Description	BED	CVPS	GMP	VEC	WEC	Smaller Utilities
Critical Period Avg. Hourly Demand	0.79	0.98	1.04	0.95	0.88	0.89
Critical Period Avg. Hourly Demand Change (kW)	-0.08	-0.10	-0.10	-0.09	-0.08	-0.09
Critical Period Avg. Hourly Demand Change (%)	-10.00%	-10.24%	-9.86%	-9.36%	-9.50%	-10.09%
Annual Energy Consumption (kWh)	5,628.0	6,928.5	7,399.9	6,732.2	6,231.0	6,339.0
Change in Energy Consumption (kWh)	-7.2	-9.1	-9.2	-7.8	-7.4	-8.2
Change in Energy Consumption (%)	-0.13%	-0.13%	-0.13%	-0.12%	-0.12%	-0.13%
Annual Bill Savings	-\$5.18	-\$6.47	-\$6.74	-\$5.91	-\$5.53	-\$5.87
% Change in Annual Bill (new rates, old usage)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
% Change in Annual Bill (new rates, new usage)	-0.66%	-0.68%	-0.64%	-0.54%	-0.58%	-0.66%
% Change in Summer Bill(new rate, new usage)	-4.72%	-4.85%	-4.52%	-3.88%	-4.06%	-4.72%

Table D-13
Base Peak Time Rebate (75c) Average Commercial Rate 1
Demand, Energy, and Billing Impacts (Starting Values)

Result Description	CVPS	GMP	VEC	BED	WEC	Smaller Utilities
Critical Period Avg. Hourly Demand	10.95	8.13	14.77	-	-	4.80
Critical Period Avg. Hourly Demand Change (kW)	-0.79	-0.64	-1.21	-	-	-0.36
Critical Period Avg. Hourly Demand Change (%)	-7.19%	-7.85%	-8.21%	-	-	-7.57%
Annual Energy Consumption (kWh)	48,759.3	36,217	65,754	-	-	21,384
Change in Energy Consumption (kWh)	-56.3	-46.5	-89.2	-	-	-26.3
Change in Energy Consumption (%)	-0.12%	-0.13%	-0.14%	-	-	-0.12%
Annual Bill Savings	-\$50.69	-\$40.13	-\$75.32	-	-	-\$23.07
% Change in Annual Bill (new rates, old usage)	0.00%	0.00%	0.00%	-	-	0.00%
% Change in Annual Bill (new rates, new usage)	-0.71%	-0.89%	-0.95%	-	-	-0.80%
% Change in Summer Bill(new rate, new usage)	-4.91%	-6.21%	-7.23%	-	-	-5.55%

Table D-14
Base Peak Time Rebate (75c) Average Commercial Rate 2
Demand, Energy, and Billing Impacts (Starting Values)

Result Description	BED	CVPS	GMP	VEC	WEC	Smaller Utilities
Critical Period Avg. Hourly Demand	40.13	54.13	30.28	27.96	36.50	16.21
Critical Period Avg. Hourly Demand Change (kW)	-3.28	-4.28	-2.43	-2.25	-2.96	-1.27
Critical Period Avg. Hourly Demand Change (%)	-8.18%	-7.91%	-8.04%	-8.05%	-8.11%	-7.81%
Annual Energy Consumption (kWh)	231,892	312,808	174,486	161,591	210,938	93,693
Change in Energy Consumption (kWh)	-252.2	-326.1	-186.1	-172.1	-227.0	-96.1
Change in Energy Consumption (%)	-0.11%	-0.10%	-0.11%	-0.11%	-0.11%	-0.10%
Annual Bill Savings	-\$206.49	-\$269.35	-\$152.22	-\$142.15	-\$186.67	-\$80.66
% Change in Annual Bill (new rates, old usage)	0.00%	0.01%	0.01%	0.00%	0.00%	0.00%
% Change in Annual Bill (new rates, new usage)	-0.79%	-0.65%	-0.76%	-0.73%	-0.77%	-0.66%
% Change in Summer Bill(new rate, new usage)	-5.32%	-4.58%	-5.34%	-5.10%	-5.12%	-4.54%

Table D-15
Estimated Average Residential Customer
Demand, Energy, and Billing Impacts (Starting Values)
by Peak Time Rebate Size

Result Description		Peak Time Adder	\$0.20	\$0.30	\$0.40	\$0.50	\$0.60	\$0.70	\$0.80	\$0.90	\$1.00
BED	Critical Period Avg. Hourly Demand		0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79
	Critical Period Avg. Hourly Demand Change (kW)		-0.04	-0.05	-0.06	-0.06	-0.07	-0.08	-0.08	-0.09	-0.09
	Critical Period Avg. Hourly Demand Change (%)		-4.65%	-6.05%	-7.18%	-8.13%	-8.95%	-9.67%	-10.32%	-10.90%	-11.43%
	Annual Energy Consumption (kWh)		5,628.0	5,628.0	5,628.0	5,628.0	5,628.0	5,628.0	5,628.0	5,628.0	5,628.0
	Change in Energy Consumption (kWh)		-2.7	-3.7	-4.6	-5.4	-6.2	-6.8	-7.5	-8.0	-8.5
	Change in Energy Consumption (%)		-0.05%	-0.07%	-0.08%	-0.10%	-0.11%	-0.12%	-0.13%	-0.14%	-0.15%
	Annual Bill Savings		-\$0.86	-\$1.50	-\$2.22	-\$3.00	-\$3.84	-\$4.72	-\$5.64	-\$6.60	-\$7.59
	% Change in Annual Bill (new rates, old usage)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	% Change in Annual Bill (new rates, new usage)		-0.11%	-0.19%	-0.28%	-0.38%	-0.49%	-0.61%	-0.72%	-0.85%	-0.97%
	% Change in Summer Bill(new rate, new usage)		-0.69%	-1.26%	-1.92%	-2.65%	-3.44%	-4.28%	-5.16%	-6.08%	-7.04%
CVPS	Critical Period Avg. Hourly Demand		0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
	Critical Period Avg. Hourly Demand Change (kW)		-0.05	-0.06	-0.07	-0.08	-0.09	-0.10	-0.10	-0.11	-0.11
	Critical Period Avg. Hourly Demand Change (%)		-4.80%	-6.23%	-7.38%	-8.34%	-9.17%	-9.90%	-10.55%	-11.14%	-11.67%
	Annual Energy Consumption (kWh)		6,928.5	6,928.5	6,928.5	6,928.5	6,928.5	6,928.5	6,928.5	6,928.5	6,928.5
	Change in Energy Consumption (kWh)		-3.4	-4.7	-5.9	-6.9	-7.8	-8.7	-9.5	-10.2	-10.8
	Change in Energy Consumption (%)		-0.05%	-0.07%	-0.09%	-0.10%	-0.11%	-0.13%	-0.14%	-0.15%	-0.16%
	Annual Bill Savings		-\$1.08	-\$1.88	-\$2.77	-\$3.75	-\$4.80	-\$5.90	-\$7.06	-\$8.25	-\$9.49
	% Change in Annual Bill (new rates, old usage)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	% Change in Annual Bill (new rates, new usage)		-0.11%	-0.20%	-0.29%	-0.39%	-0.50%	-0.62%	-0.74%	-0.87%	-1.00%
	% Change in Summer Bill (new rate, new usage)		-0.72%	-1.30%	-1.98%	-2.73%	-3.54%	-4.40%	-5.31%	-6.25%	-7.23%
GMP	Critical Period Avg. Hourly Demand		1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04
	Critical Period Avg. Hourly Demand Change (kW)		-0.05	-0.06	-0.07	-0.08	-0.09	-0.10	-0.11	-0.11	-0.12
	Critical Period Avg. Hourly Demand Change (%)		-4.55%	-5.93%	-7.05%	-8.00%	-8.81%	-9.53%	-10.17%	-10.75%	-11.28%
	Annual Energy Consumption (kWh)		7,399.9	7,399.9	7,399.9	7,399.9	7,399.9	7,399.9	7,399.9	7,399.9	7,399.9
	Change in Energy Consumption (kWh)		-3.4	-4.8	-5.9	-7.0	-8.0	-8.8	-9.6	-10.4	-11.0
	Change in Energy Consumption (%)		-0.05%	-0.06%	-0.08%	-0.10%	-0.11%	-0.12%	-0.13%	-0.14%	-0.15%
	Annual Bill Savings		-\$1.12	-\$1.95	-\$2.88	-\$3.90	-\$4.99	-\$6.14	-\$7.34	-\$8.59	-\$9.88
	% Change in Annual Bill (new rates, old usage)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	% Change in Annual Bill (new rates, new usage)		-0.11%	-0.18%	-0.27%	-0.37%	-0.47%	-0.58%	-0.70%	-0.81%	-0.94%
	% Change in Summer Bill(new rate, new usage)		-0.66%	-1.21%	-1.84%	-2.54%	-3.30%	-4.10%	-4.95%	-5.83%	-6.75%
VEC	Critical Period Avg. Hourly Demand		0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
	Critical Period Avg. Hourly Demand Change (kW)		-0.04	-0.05	-0.06	-0.07	-0.08	-0.09	-0.09	-0.10	-0.10
	Critical Period Avg. Hourly Demand Change (%)		-4.23%	-5.55%	-6.63%	-7.55%	-8.34%	-9.04%	-9.67%	-10.23%	-10.75%
	Annual Energy Consumption (kWh)		6,732.2	6,732.2	6,732.2	6,732.2	6,732.2	6,732.2	6,732.2	6,732.2	6,732.2
	Change in Energy Consumption (kWh)		-2.8	-4.0	-5.0	-5.9	-6.7	-7.5	-8.2	-8.8	-9.4
	Change in Energy Consumption (%)		-0.04%	-0.06%	-0.07%	-0.09%	-0.10%	-0.11%	-0.12%	-0.13%	-0.14%
	Annual Bill Savings		-\$0.98	-\$1.71	-\$2.53	-\$3.42	-\$4.38	-\$5.39	-\$6.45	-\$7.55	-\$8.69
	% Change in Annual Bill (new rates, old usage)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	% Change in Annual Bill (new rates, new usage)		-0.09%	-0.16%	-0.23%	-0.31%	-0.40%	-0.49%	-0.58%	-0.69%	-0.78%
	% Change in Summer Bill(new rate, new usage)		-0.57%	-1.03%	-1.57%	-2.17%	-2.82%	-3.52%	-4.25%	-5.01%	-5.80%
WEC	Critical Period Avg. Hourly Demand		0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88
	Critical Period Avg. Hourly Demand Change (kW)		-0.04	-0.05	-0.06	-0.07	-0.07	-0.08	-0.09	-0.09	-0.10
	Critical Period Avg. Hourly Demand Change (%)		-4.32%	-5.66%	-6.75%	-7.67%	-8.47%	-9.18%	-9.81%	-10.38%	-10.90%
	Annual Energy Consumption (kWh)		6,231.0	6,231.0	6,231.0	6,231.0	6,231.0	6,231.0	6,231.0	6,231.0	6,231.0
	Change in Energy Consumption (kWh)		-2.7	-3.8	-4.7	-5.6	-6.4	-7.1	-7.7	-8.3	-8.9
	Change in Energy Consumption (%)		-0.04%	-0.06%	-0.08%	-0.09%	-0.10%	-0.11%	-0.12%	-0.13%	-0.14%
	Annual Bill Savings		-\$0.92	-\$1.60	-\$2.36	-\$3.20	-\$4.09	-\$5.04	-\$6.03	-\$7.06	-\$8.12
	% Change in Annual Bill (new rates, old usage)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	% Change in Annual Bill (new rates, new usage)		-0.10%	-0.17%	-0.25%	-0.33%	-0.43%	-0.52%	-0.63%	-0.73%	-0.84%
	% Change in Summer Bill(new rate, new usage)		-0.59%	-1.08%	-1.65%	-2.27%	-2.95%	-3.68%	-4.44%	-5.24%	-6.07%
Smaller Utilities	Critical Period Avg. Hourly Demand		0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
	Critical Period Avg. Hourly Demand Change (kW)		-0.04	-0.05	-0.06	-0.07	-0.08	-0.09	-0.09	-0.10	-0.10
	Critical Period Avg. Hourly Demand Change (%)		-4.70%	-6.12%	-7.25%	-8.21%	-9.04%	-9.76%	-10.41%	-10.99%	-11.52%
	Annual Energy Consumption (kWh)		6,339.0	6,339.0	6,339.0	6,339.0	6,339.0	6,339.0	6,339.0	6,339.0	6,339.0
	Change in Energy Consumption (kWh)		-3.0	-4.2	-5.3	-6.2	-7.0	-7.8	-8.5	-9.1	-9.7
	Change in Energy Consumption (%)		-0.05%	-0.07%	-0.08%	-0.10%	-0.11%	-0.12%	-0.13%	-0.14%	-0.15%
	Annual Bill Savings		-\$0.98	-\$1.70	-\$2.51	-\$3.40	-\$4.35	-\$5.35	-\$6.39	-\$7.48	-\$8.60
	% Change in Annual Bill (new rates, old usage)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	% Change in Annual Bill (new rates, new usage)		-0.11%	-0.19%	-0.28%	-0.38%	-0.49%	-0.61%	-0.72%	-0.85%	-0.97%
	% Change in Summer Bill(new rate, new usage)		-0.70%	-1.27%	-1.93%	-2.66%	-3.45%	-4.29%	-5.17%	-6.09%	-7.04%

Table D-16
Estimated Average Commercial Rate 1 Customer
Demand, Energy, and Billing Impacts (Starting Values)
by Peak Time Rebate Size

Result Description		Peak Time Adder	\$0.20	\$0.30	\$0.40	\$0.50	\$0.60	\$0.70	\$0.80	\$0.90	\$1.00
BED	Critical Period Avg. Hourly Demand										
	Critical Period Avg. Hourly Demand Change (kW)										
	Critical Period Avg. Hourly Demand Change (%)										
	Annual Energy Consumption (kWh)										
	Change in Energy Consumption (kWh)										
	Change in Energy Consumption (%)										
	Annual Bill Savings										
	% Change in Annual Bill (new rates, old usage)										
CVPS	Critical Period Avg. Hourly Demand		10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95
	Critical Period Avg. Hourly Demand Change (kW)		-0.35	-0.47	-0.56	-0.63	-0.70	-0.76	-0.81	-0.86	-0.90
	Critical Period Avg. Hourly Demand Change (%)		-3.24%	-4.26%	-5.09%	-5.79%	-6.40%	-6.94%	-7.42%	-7.86%	-8.25%
	Annual Energy Consumption (kWh)		48,759.3	48,759.3	48,759.3	48,759.3	48,759.3	48,759.3	48,759.3	48,759.3	48,759.3
	Change in Energy Consumption (kWh)		-21.8	-30.1	-37.1	-43.4	-48.9	-54.0	-58.5	-62.7	-66.6
	Change in Energy Consumption (%)		-0.05%	-0.06%	-0.08%	-0.09%	-0.10%	-0.11%	-0.12%	-0.13%	-0.14%
	Annual Bill Savings		-\$8.28	-\$14.45	-\$21.46	-\$29.16	-\$37.42	-\$46.16	-\$55.33	-\$64.87	-\$74.76
	% Change in Annual Bill (new rates, old usage)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GMP	Critical Period Avg. Hourly Demand		8.13	8.13	8.13	8.13	8.13	8.13	8.13	8.13	8.13
	Critical Period Avg. Hourly Demand Change (kW)		-0.30	-0.39	-0.46	-0.52	-0.57	-0.62	-0.66	-0.69	-0.73
	Critical Period Avg. Hourly Demand Change (%)		-3.67%	-4.77%	-5.66%	-6.40%	-7.04%	-7.59%	-8.09%	-8.54%	-8.95%
	Annual Energy Consumption (kWh)		36,216.8	36,216.8	36,216.8	36,216.8	36,216.8	36,216.8	36,216.8	36,216.8	36,216.8
	Change in Energy Consumption (kWh)		-18.8	-25.5	-31.3	-36.3	-40.7	-44.7	-48.3	-51.6	-54.6
	Change in Energy Consumption (%)		-0.05%	-0.07%	-0.09%	-0.10%	-0.11%	-0.12%	-0.13%	-0.14%	-0.15%
	Annual Bill Savings		-\$6.58	-\$11.48	-\$17.05	-\$23.15	-\$29.67	-\$36.56	-\$43.78	-\$51.27	-\$59.03
	% Change in Annual Bill (new rates, old usage)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
VEC	Critical Period Avg. Hourly Demand		14.77	14.77	14.77	14.77	14.77	14.77	14.77	14.77	14.77
	Critical Period Avg. Hourly Demand Change (kW)		-0.58	-0.75	-0.88	-0.99	-1.09	-1.17	-1.25	-1.32	-1.38
	Critical Period Avg. Hourly Demand Change (%)		-3.91%	-5.06%	-5.97%	-6.73%	-7.38%	-7.95%	-8.46%	-8.91%	-9.32%
	Annual Energy Consumption (kWh)		65,754.0	65,754.0	65,754.0	65,754.0	65,754.0	65,754.0	65,754.0	65,754.0	65,754.0
	Change in Energy Consumption (kWh)		-36.7	-49.7	-60.6	-70.1	-78.4	-85.8	-92.5	-98.6	-104.2
	Change in Energy Consumption (%)		-0.06%	-0.08%	-0.09%	-0.11%	-0.12%	-0.13%	-0.14%	-0.15%	-0.16%
	Annual Bill Savings		-\$12.37	-\$21.61	-\$32.08	-\$43.51	-\$55.74	-\$68.64	-\$82.13	-\$96.15	-\$110.63
	% Change in Annual Bill (new rates, old usage)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
WEC	Critical Period Avg. Hourly Demand										
	Critical Period Avg. Hourly Demand Change (kW)										
	Critical Period Avg. Hourly Demand Change (%)										
	Annual Energy Consumption (kWh)										
	Change in Energy Consumption (kWh)										
	Change in Energy Consumption (%)										
	Annual Bill Savings										
	% Change in Annual Bill (new rates, old usage)										
Smaller Utilities	Critical Period Avg. Hourly Demand		4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80
	Critical Period Avg. Hourly Demand Change (kW)		-0.17	-0.22	-0.26	-0.29	-0.33	-0.35	-0.38	-0.40	-0.42
	Critical Period Avg. Hourly Demand Change (%)		-3.48%	-4.55%	-5.42%	-6.14%	-6.77%	-7.32%	-7.81%	-8.25%	-8.65%
	Annual Energy Consumption (kWh)		21,384.0	21,384.0	21,384.0	21,384.0	21,384.0	21,384.0	21,384.0	21,384.0	21,384.0
	Change in Energy Consumption (kWh)		-10.4	-14.3	-17.5	-20.4	-22.9	-25.2	-27.3	-29.2	-30.9
	Change in Energy Consumption (%)		-0.05%	-0.07%	-0.08%	-0.10%	-0.11%	-0.12%	-0.13%	-0.14%	-0.15%
	Annual Bill Savings		-\$3.77	-\$6.59	-\$9.79	-\$13.29	-\$17.05	-\$21.02	-\$25.18	-\$29.50	-\$33.98
	% Change in Annual Bill (new rates, old usage)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table D-17
Estimated Average Commercial Rate 2 Customer
Demand, Energy, and Billing Impacts (Starting Values)
by Peak Time Rebate Size

Result Description		Peak Time Adder	\$0.20	\$0.30	\$0.40	\$0.50	\$0.60	\$0.70	\$0.80	\$0.90	\$1.00
BED	Critical Period Avg. Hourly Demand		40.13	40.13	40.13	40.13	40.13	40.13	40.13	40.13	40.13
	Critical Period Avg. Hourly Demand Change (kW)		-1.55	-2.01	-2.37	-2.68	-2.95	-3.18	-3.38	-3.57	-3.74
	Critical Period Avg. Hourly Demand Change (%)		-3.86%	-5.00%	-5.92%	-6.68%	-7.34%	-7.92%	-8.43%	-8.89%	-9.31%
	Annual Energy Consumption (kWh)		231,892	231,892	231,892	231,892	231,892	231,892	231,892	231,892	231,892
	Change in Energy Consumption (kWh)		-99.2	-136.0	-167.6	-195.3	-219.8	-241.9	-262.0	-280.4	-297.4
	Change in Energy Consumption (%)		-0.04%	-0.06%	-0.07%	-0.08%	-0.10%	-0.10%	-0.11%	-0.12%	-0.13%
	Annual Bill Savings		-\$33.80	-\$59.11	-\$87.81	-\$119.16	-\$152.72	-\$188.15	-\$225.22	-\$263.73	-\$303.54
	% Change in Annual Bill (new rates, old usage)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	% Change in Annual Bill (new rates, new usage)		-0.13%	-0.22%	-0.33%	-0.45%	-0.58%	-0.72%	-0.86%	-1.00%	-1.15%
	% Change in Summer Bill(new rate, new usage)		-0.78%	-1.42%	-2.17%	-2.99%	-3.88%	-4.83%	-5.82%	-6.86%	-7.94%
CVPS	Critical Period Avg. Hourly Demand		54.13	54.13	54.13	54.13	54.13	54.13	54.13	54.13	54.13
	Critical Period Avg. Hourly Demand Change (kW)		-1.99	-2.59	-3.08	-3.48	-3.83	-4.14	-4.42	-4.66	-4.89
	Critical Period Avg. Hourly Demand Change (%)		-3.68%	-4.79%	-5.69%	-6.44%	-7.08%	-7.65%	-8.16%	-8.62%	-9.03%
	Annual Energy Consumption (kWh)		312,808	312,808	312,808	312,808	312,808	312,808	312,808	312,808	312,808
	Change in Energy Consumption (kWh)		-126.4	-174.0	-215.1	-251.3	-283.5	-312.6	-339.1	-363.4	-385.8
	Change in Energy Consumption (%)		-0.04%	-0.06%	-0.07%	-0.08%	-0.09%	-0.10%	-0.11%	-0.12%	-0.13%
	Annual Bill Savings		-\$41.81	-\$75.09	-\$112.85	-\$154.15	-\$198.39	-\$245.14	-\$294.07	-\$344.94	-\$397.55
	% Change in Annual Bill (new rates, old usage)		0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
	% Change in Annual Bill (new rates, new usage)		-0.10%	-0.18%	-0.27%	-0.37%	-0.48%	-0.59%	-0.71%	-0.83%	-0.96%
	% Change in Summer Bill (new rate, new usage)		-0.65%	-1.20%	-1.84%	-2.56%	-3.33%	-4.15%	-5.02%	-5.92%	-6.86%
GMP	Critical Period Avg. Hourly Demand		30.28	30.28	30.28	30.28	30.28	30.28	30.28	30.28	30.28
	Critical Period Avg. Hourly Demand Change (kW)		-1.14	-1.48	-1.75	-1.98	-2.18	-2.35	-2.51	-2.65	-2.77
	Critical Period Avg. Hourly Demand Change (%)		-3.76%	-4.89%	-5.79%	-6.55%	-7.20%	-7.78%	-8.29%	-8.75%	-9.16%
	Annual Energy Consumption (kWh)		174,486	174,486	174,486	174,486	174,486	174,486	174,486	174,486	174,486
	Change in Energy Consumption (kWh)		-72.6	-99.8	-123.2	-143.7	-162.0	-178.5	-193.4	-207.2	-219.8
	Change in Energy Consumption (%)		-0.04%	-0.06%	-0.07%	-0.08%	-0.09%	-0.10%	-0.11%	-0.12%	-0.13%
	Annual Bill Savings		-\$23.47	-\$42.33	-\$63.70	-\$87.08	-\$112.10	-\$138.53	-\$166.19	-\$194.94	-\$224.66
	% Change in Annual Bill (new rates, old usage)		0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
	% Change in Annual Bill (new rates, new usage)		-0.12%	-0.21%	-0.32%	-0.43%	-0.56%	-0.69%	-0.83%	-0.97%	-1.12%
	% Change in Summer Bill(new rate, new usage)		-0.75%	-1.40%	-2.15%	-2.98%	-3.88%	-4.84%	-5.84%	-6.90%	-7.98%
VEC	Critical Period Avg. Hourly Demand		27.96	27.96	27.96	27.96	27.96	27.96	27.96	27.96	27.96
	Critical Period Avg. Hourly Demand Change (kW)		-1.05	-1.37	-1.62	-1.83	-2.02	-2.18	-2.32	-2.45	-2.56
	Critical Period Avg. Hourly Demand Change (%)		-3.77%	-4.90%	-5.80%	-6.56%	-7.21%	-7.78%	-8.29%	-8.75%	-9.17%
	Annual Energy Consumption (kWh)		161,591	161,591	161,591	161,591	161,591	161,591	161,591	161,591	161,591
	Change in Energy Consumption (kWh)		-67.2	-92.3	-113.9	-132.9	-149.8	-165.0	-178.9	-191.5	-203.3
	Change in Energy Consumption (%)		-0.04%	-0.06%	-0.07%	-0.08%	-0.09%	-0.10%	-0.11%	-0.12%	-0.13%
	Annual Bill Savings		-\$23.24	-\$40.65	-\$60.39	-\$81.98	-\$105.10	-\$129.51	-\$155.06	-\$181.61	-\$209.07
	% Change in Annual Bill (new rates, old usage)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	% Change in Annual Bill (new rates, new usage)		-0.12%	-0.21%	-0.31%	-0.42%	-0.54%	-0.67%	-0.80%	-0.94%	-1.08%
	% Change in Summer Bill(new rate, new usage)		-0.74%	-1.36%	-2.07%	-2.86%	-3.72%	-4.62%	-5.58%	-6.58%	-7.61%
WEC	Critical Period Avg. Hourly Demand		36.50	36.50	36.50	36.50	36.50	36.50	36.50	36.50	36.50
	Critical Period Avg. Hourly Demand Change (kW)		-1.39	-1.81	-2.14	-2.42	-2.66	-2.86	-3.05	-3.22	-3.37
	Critical Period Avg. Hourly Demand Change (%)		-3.81%	-4.95%	-5.86%	-6.62%	-7.27%	-7.85%	-8.36%	-8.82%	-9.24%
	Annual Energy Consumption (kWh)		210,938	210,938	210,938	210,938	210,938	210,938	210,938	210,938	210,938
	Change in Energy Consumption (kWh)		-88.9	-122.1	-150.5	-175.5	-197.7	-217.7	-235.8	-252.5	-267.8
	Change in Energy Consumption (%)		-0.04%	-0.06%	-0.07%	-0.08%	-0.09%	-0.10%	-0.11%	-0.12%	-0.13%
	Annual Bill Savings		-\$30.54	-\$53.41	-\$79.34	-\$107.69	-\$138.03	-\$170.08	-\$203.61	-\$238.45	-\$274.47
	% Change in Annual Bill (new rates, old usage)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	% Change in Annual Bill (new rates, new usage)		-0.13%	-0.22%	-0.33%	-0.44%	-0.57%	-0.70%	-0.84%	-0.98%	-1.13%
	% Change in Summer Bill(new rate, new usage)		-0.75%	-1.36%	-2.08%	-2.87%	-3.73%	-4.64%	-5.60%	-6.60%	-7.64%
Smaller Utilities	Critical Period Avg. Hourly Demand		16.21	16.21	16.21	16.21	16.21	16.21	16.21	16.21	16.21
	Critical Period Avg. Hourly Demand Change (kW)		-0.59	-0.76	-0.91	-1.03	-1.13	-1.22	-1.31	-1.38	-1.45
	Critical Period Avg. Hourly Demand Change (%)		-3.62%	-4.71%	-5.60%	-6.34%	-6.99%	-7.55%	-8.06%	-8.51%	-8.93%
	Annual Energy Consumption (kWh)		93,693	93,693	93,693	93,693	93,693	93,693	93,693	93,693	93,693
	Change in Energy Consumption (kWh)		-37.0	-51.1	-63.2	-73.9	-83.5	-92.1	-99.9	-107.2	-113.8
	Change in Energy Consumption (%)		-0.04%	-0.05%	-0.07%	-0.08%	-0.09%	-0.10%	-0.11%	-0.11%	-0.12%
	Annual Bill Savings		-\$13.17	-\$23.02	-\$34.22	-\$46.47	-\$59.60	-\$73.47	-\$88.00	-\$103.11	-\$118.74
	% Change in Annual Bill (new rates, old usage)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	% Change in Annual Bill (new rates, new usage)		-0.11%	-0.19%	-0.28%	-0.38%	-0.49%	-0.60%	-0.72%	-0.84%	-0.97%
	% Change in Summer Bill(new rate, new usage)		-0.66%	-1.20%	-1.84%	-2.54%	-3.31%	-4.12%	-4.98%	-5.87%	-6.79%

D.8. CUSTOMER PARTICIPATION/AWARENESS

The estimated demand response benefits in this analysis are based on achieving an awareness level for the PTR program of 50% among residential consumers and 25% among medium commercial and industrial (C&I) customers. The 50% value for residential customers is the same awareness level that the California Public Utilities Commission (CPUC) accepted as reasonably achievable when it approved San Diego Gas and Electric Company's (SDG&E) recent AMI application.¹² SDG&E provided testimony indicating that a 70% awareness level was achievable.¹³

¹² California Public Utilities Commission. *Opinion Approving Settlement on San Diego Gas & Electric Company's Advanced Metering Infrastructure project*. Application 05-03-015. Decision 07-04-043. April 12, 2007.

¹³ Prepared Supplemental, Consolidating, Superseding and Replacement Testimony of Mr. Mark F. Gaines on behalf of SDG&E. *Chapter 5: AMI Marketing and Customer Programs*. July 14, 2006 Amendment.

APPENDIX E. AVOIDED CAPACITY, ENERGY & ENVIRONMENTAL COSTS

The value of DR is related to its magnitude, timing, and duration. Generally, DR has its greatest value as insurance against low probability events that have severe consequences either in terms of price or reliability. This is true for both reliability and price-triggered DR. The bulk of DR value comes from offsetting investments that would otherwise occur in order to safeguard the grid from the strain of high peak demand levels. This appendix focuses on the value of demand response within the context of the ISO-NE market, and not on quantifying the expected load reductions given Vermont customer characteristics, weather, and retail prices. In particular, the emphasis is on the costs avoided from a total resource cost perspective, and on the four main benefit streams of DR:

- Avoided generation capacity costs
- Avoided transmission costs
- Avoided distribution costs
- Avoided energy costs

In addition, the analysis calculated the environmental benefits associated with the energy savings directly attributable to demand response under a broader test, referred to as the TRC plus test throughout the report.

Noticeably absent from the benefit streams listed above is the impact of demand response on lower market clearing prices. As has been shown repeatedly, a reduction in demand at the right time can cause a large decrease in wholesale market prices, resulting in significant customer savings. From a traditional societal perspective, however, lower market prices lead to a transfer from generators to consumers but do not represent a net benefit.

E.1. AVOIDED GENERATION CAPACITY COSTS

Electricity systems are built for extreme conditions. Because of the relatively high cost of customer outages and the resulting high premium on grid reliability, the electricity system is typically constructed so as to experience loss of load no more than 1 day in 10 years. Having sufficient supply resources available and operational for extreme conditions is a critical component of system planning and is incorporated into the ISO-NE market in the form of installed capacity requirements that must be met. The cost of capacity is determined in the ISO-NE Forward Capacity Market (FCM).

E.1.1. Determining Avoided Generation Capacity Value

As discussed in detail in Appendix D and in the main body of the report, time-based pricing reduces demand at times of system peak. At the simplest level, the value of this type of demand response equals the load reduction grossed up for avoided lines losses times the capacity value times the reserve margins implicit in the installed capacity requirements. Equation E-1 below summarizes this calculation.

$$\text{Avoided Generation Capacity Costs} = (\text{load reduction}) \times (1 + \text{line losses}) \times (\text{capacity cost}) \times (1 + \text{reserve margin}) \quad (\text{E-1})$$

Estimates of the change in demand at the time of system peak are discussed in Appendix D and in the main report. Estimates of line losses vary across utilities and were obtained through responses to the data requests submitted to each utility. The reported values are shown in Table E-1 below. The determination of capacity costs and reserve margins are documented below.

Table E-1
Line Losses

Provider	Average Line Losses
CVPS	5.36%
GMP	4.30%
VCE	9.54%
BED	2.58%
WEC	8.07%
Small Utilities	10.38%

E.1.2. Capacity Value and Escalation

Capacity value is typically calculated as the cost, in dollars per kW-year, of having a marginal peaking resource available and operational. This is also referred to as the cost-of-new-entry (CONE) for a peaking unit.

By design, capacity markets 1) set reliability levels via installed capacity requirements, 2) provide a venue for marginal peaking units to recover the costs associated with remaining available and operational (capacity costs), and 3) reflect the fact that additional capacity is more valuable when there is a shortage of resources and less valuable when there is an excess. Importantly, capacity markets are typically designed to trend toward the equilibrium capacity value. Given the lack of FCM historical data and the market tendency towards equilibrium, the levelized costs of having the marginal peaking resource available and operational –\$90 per kW-year, according to ISO-NE – was employed as the estimated equilibrium capacity value.

The ISO-NE has designed the FCM around the capacity value of \$7.50 per month or \$90 per kW-year, which is also referred to as the cost of new entry (CONE). Using this value as the expected equilibrium capacity value is consistent with the approach taken in the Forward Capacity Market design and implementation, which sets the initial price in the descending clock auction at two times the cost of new entry and has embedded price floors based on the cost of new entry for the initial FCM auctions.

In the analysis presented in this report, the FCM transition prices were employed for the years 2008, 2009 and 2010. After 2010, capacity values were assumed to ramp up over three years to the long run equilibrium value, as represented by the ISO adopted cost of

new entry (CONE), and held at the equilibrium value in real terms through the rest of the analysis period. Finally, the cost of capacity is projected to escalate at 4.0% per year.¹⁴ Table E-2 contains the capacity costs in real and nominal terms that underlie the benefit-cost analysis presented here.

TABLE E-2: CAPACITY COSTS

Year	Capacity Value 2007 dollars (\$/kW-year)	Capacity Inflation Factor (3.0%)	Capacity Value Nominal dollars (\$/kW-year)
2007	\$45.00		\$45.00
2008	\$47.10		\$47.10
2009	\$49.20		\$49.20
2010	\$62.80	1.093	\$68.63
2011	\$71.87	1.126	\$80.90
2012	\$83.96	1.159	\$97.34
2013	\$90.00	1.194	\$107.49
2014	\$90.00	1.230	\$110.71
2015	\$90.00	1.267	\$114.04
2016	\$90.00	1.305	\$117.46
2017	\$90.00	1.344	\$120.99
2018	\$90.00	1.385	\$124.62
2019	\$90.00	1.426	\$128.37
2020	\$90.00	1.469	\$132.22
2021	\$90.00	1.513	\$136.19
2022	\$90.00	1.559	\$140.28
2023	\$90.00	1.606	\$144.50
2024	\$90.00	1.654	\$148.84
2025	\$90.00	1.703	\$153.31
2026	\$90.00	1.755	\$157.91
2027	\$90.00	1.807	\$162.65
2028	\$90.00	1.862	\$167.54
2029	\$90.00	1.917	\$172.57
2030	\$90.00	1.975	\$177.75

E.1.3. Installed Capacity Requirements

Installed capacity requirements determine how much capacity needs to be purchased to meet a given load. The installed capacity requirement is determined by the ISO-NE based on expected peak demand (50/50 forecast), supply resources within an area, hydro

¹⁴ See Appendix G for a detailed explanation of how the capacity escalation factor was determined.

conditions, and interconnections.¹⁵ Importantly, the ISO-NE does not have a required reserve margin as in other regions with capacity markets. Instead, the installed capacity requirements are calculated periodically and are often referred to as resulting reserves, which is the amount of capacity the system must maintain (in percentage terms) above the expected system-wide peak demand.

Table E-3 contains the estimated installed capacity requirements for 2008 to 2016 published by the ISO-NE in the 2007 Regional System Plan.¹⁶ Our analysis employed the reserve margins implicit in the representative installed capacity requirements through 2016. Thereafter, we kept the reserve margin at the 2015 value of 16.6%. Note that these values were based on the ISO-NE probabilistic simulation and are the ISO's estimates of future installed capacity requirements. Actual installed capacity requirements may vary.

¹⁵ See ISO Manual 20 or the ISO-NE document titled "ISO New England Installed Capacity Requirements for the 2007-2008 Power Year" for detailed explanations on how installed capacity requirement are calculated. The ISO-NE's installed capacity requirements are calculated using the following formula:

$$\text{Installed Capacity Requirements (ICR)} = \left[\frac{\text{Capacity} - \text{Tie Benefits} - \text{OP4 Load Relief}}{1 + \frac{\text{ALCC}}{\text{APk}}} \right] + \text{HQICC} - \text{NYPA} + \text{Hydro Adj}$$

Where:

Annual Peak	= Annual Peak Load Forecast for Summer 2007
Capacity	= Total Monthly Capacity (Sum of all supply resources)
Tie Benefits	= Monthly Tie Reliability Benefits
OP4 Load Relief	= Monthly Load Relief from OP-4
ALCC	= Additional Load Carrying Capability (as determined from the Capacity Model)
HQICC	= Monthly Hydro-Québec Interconnection Capability Credit
NYPA	= Grandfathered New York Power Authority (NYPA) Contracts
Hydro Adj. rate	= Difference between Daily Cycle Hydro Ratings at 80% flow rate and 50% flow rate

Table E-3
ISO-NE Peak Forecasts, Capacity Requirements and Reserve Margins

Year	Summer Peak Load Forecast 50/50	Representative Future Installed	Reserve Margin
		Capacity Requirements	
2008	27,855	31,848	14.3%
2009	28,495	32,657	14.6%
2010	29,035	33,705	16.1%
2011	29,635	34,449	16.2%
2012	30,175	35,103	16.3%
2013	30,660	35,716	16.5%
2014	31,100	36,250	16.6%
2015	31,510	36,755	16.6%
2016	31,885	37,187	16.6%

Source: ISO-NE Regional System Plan 2007

E.1.4. How DR Helps Avoid Generation Capacity Costs

In the New England market, demand response can participate as a supply side resource in the FCM and collect capacity payments, or it can be employed by utilities to reduce the share of capacity payments that is allocated to them. Put differently, from a utility's perspective, demand response can be used to capture payments via the FCM that offset allocated capacity costs or it can be used to reduce capacity costs allocated to a utility. In the analysis reported here, the avoided capacity was valued using the second approach.

The FCM market does allow demand response to participate as a supply side resource provided it meet one of five Demand Resource Type definitions and go through a qualification process. The ISO-NE's Demand Resource Types were not designed for time varying prices with day-ahead notification. In addition, participating as a demand side resource increases the administrative burden for the utility due to the qualification period and auction participation. As result, the best option for utilities to avoided capacity costs with time varying pricing is to affect the capacity cost allocation by lowering the load coincident with system peak. Table E-4 details the FCM's five Demand Resource Types, their respective type of hours and availability and the types of technologies/programs they were designed for.

Table E-4
ISO-NE Peak Forecasts, Capacity Requirements and Reserve Margins

Demand Resource Type	Type of Hours and Availability	Designed For
On-Peak	<ul style="list-style-type: none"> ◆ Summer On-Peak Hours: 1:00 -5:00 p.m., Non-Holiday Week Days in June, July, and August ◆ Winter On-Peak Hours: 5:00-7:00 p.m., Non-Holiday Week Days in December and January 	Designed for non-dispatchable measures that are not weather sensitive and reduce load across pre-defined hours (e.g., lighting, motors, etc.).
Seasonal Peak	Non-holiday week days when the Real-Time System Hourly Load is equal to or greater than 90% of the most recent "50/50" System Peak Load Forecast for the applicable Summer or Winter Season	Designed for non-dispatchable, weather-sensitive measures such as energy efficient HVAC measures.
Critical Peak	<ul style="list-style-type: none"> ◆ Hours when the ISO's Hourly Day-Ahead Forecasted Load (for non-holiday weekdays days) is equal to or greater than 95% of the most recent 50/50 System Peak Load Forecast for the applicable summer or winter season. ◆ Hours when the ISO implements OP-4 Action 6 or higher (See Definitions). 	Designed for measures that can be dispatched by the project owner based on system conditions.
Real-Time (RT) Demand Response	Must curtail electrical usage within 30 minutes of receiving a Dispatch Instruction; and continue curtailing usage until receiving a Dispatch Instruction to restore electrical usage.	Designed for dispatchable measures with no binding air quality permitting restrictions on their use during Critical Peak Hours.
Real-Time Emergency Generation	They must curtail electrical usage within 30 minutes of receiving a Dispatch Instruction; and continue curtailing usage until receiving a Dispatch Instruction to restore electrical usage.	Designed for dispatchable Emergency Generators only.

Source: ISO-NE Introduction to Demand Resource Participation in New England's Forward Capacity Market, presented April 20, 2007

With the ISO-NE FCM, the amount of capacity resources that will be procured is determined by the adopted installed capacity requirements and the capacity price is determined in an auction. The resulting costs are then allocated among the load serving entities (i.e., the utilities) based on the each utility's contribution to the prior year's system peak. Load reduction can effectively lower a utility's contribution to system peak and, as a result, reduce its overall allocation of capacity costs. However, there is a one-year lag between when the load is reduced and when the benefits accrue.

Table E-5 provides an example showing a utility's capacity costs with and without DR, with the difference being the utility's savings directly attributable to DR. For the example, the following assumptions were made:

- Line losses of 10%,
- Installed capacity requirement resulting in a reserve margin of 14.3%

- Capacity price at \$90/kW-year (i.e., equivalent to the estimated CONE)
- System peak load of 30,000 MW without DR
- Utility peak load at the time of the ISO-NE peak equal to 1,000 MW without demand response
- 100 MW of load reduction by the end users.

Table E-5
Example of Utility Costs with and without DR

Line	Description	No DR	DR	Units	Notes
1	Load reduction by customers	100	100	MW	Unadjusted for line losses
2	Load reduction grossed up for line losses	0	110	MW	Line 1 * (1 + Line Losses)
3	Utility load coincident with system peak	1,000	890	MW	100 MW of DR (grossed up for line losses)
4	Utility contribution to system peak	3.33%	2.98%	Percent	Line 3/ Line 6
5	Utility capacity costs	\$102.9	\$91.6	Millions	Line 4 * Line 8
6	System peak	30,000	29,890	MW	System Load with and without the DR
7	Installed capacity requirement	34,290	34,164	MW	Line 6* (1 + reserve margin)
8	System capacity costs	\$3,086.1	\$3,074.8	Millions	Line 7 * capacity value (\$/MW-year) / 1,000,000

Assuming the system peak and utility load are, respectively, 30,000 MW and 1,000 MW without DR, a demand reduction of 100 MW by customers would lower both utility and system peak load by 110 MW, after grossing up for line losses. Without DR, the utilities contribution to system peak would be 3.33%. With DR, it would be 2.98%. However, the load reduction not only affects the allocation of costs for the following year but also lowers the installed capacity requirement and the system capacity costs. Without DR, the following year's system capacity costs would be \$3,086.1 million, with \$102.9 million of those costs (3.33%) being allocated to the example utility. In contrast, with DR, the following year's system capacity costs would be \$3,074.8, with \$91.6 million of those costs (2.98%) being allocated to the example utility. In other words, deploying the DR resources reduces the utility and system capacity costs by \$11.3 million. Equation E-1, shown earlier in this appendix, produces the same results given the same inputs.

It is possible to conceive of a scenario where most utilities have DR programs that lower overall peak demand while leaving the share of contribution to system peak for each utility largely unchanged. This would lead to smaller installed capacity requirements and lower system capacity costs, thus avoiding the same amount of capacity cost. To use an analogy, such a scenario is akin to purchasing the smaller pie instead of the larger one, with the slices being proportionally smaller. In the case of capacity, the costs are proportional to the installed capacity requirements (the size of the pie).

E.2. AVOIDED TRANSMISSION & DISTRIBUTION CAPACITY COSTS

Like supply resources, transmission and distribution infrastructure investments are based on forecasted peak loads within and outside specific areas. However, local peaks are typically used for planning such investments and they are not always coincident with the system peak or with the critical system hours targeted by a time-varying rate. Overall, the need for

transmission capacity is generally (though not exclusively) coincident with the system peak demand, while the need for distribution capacity is tied more to local peaks and is less likely to be coincident with system demand.

In order to off-set transmission and distribution investments, load must be reduced at the right time periods and in the right areas. Two examples are illustrative. In the case of a looming distribution investment for a circuit dominated by residential load, the local peak might be in December around 7-8 pm (Christmas lights are popular in the neighborhood), in which case demand response in the summer between the hours of 12-6 pm would not reduce the need for incremental distribution capacity. In the case of a transmission investment, location matters. Demand response within a constrained area could offset the need for an investment, while load reduction immediately outside a constrained area might instead exacerbate the need for a transmission upgrade.

There are two main approaches to valuing the effect of demand response on transmission and distribution costs: a targeted DR approach, and a levelized cost approach. The targeted approach relies on identifying where transmission or distribution investments are imminent and targeting DR at the area in order to offset known, upcoming investments. Under this approach, the value of DR is the time value of money implicit in offsetting the transmission or distribution investment for a specific amount of time. The levelized cost approach is more general and is based on the ratio of historical T&D investments associated with new load growth to the overall growth in peak demand.

Given detailed information about upcoming investments, the targeted DR approach provides a more precise and concrete estimate of the T&D costs avoided by reducing and managing load. However, it was not feasible to foresee and conduct analysis for specific transmission and distribution investments over the next 20 years for this study. By default, a levelized cost approach was employed for the individual utility analysis.

E.2.1. Levelized T&D Capacity Value

Because DR delivers targeted load reductions for a small share of hours throughout the year, ideally, T&D capacity value would be adjusted based on a detailed analysis that estimates the likelihood that DR would indeed offset transmission and/or distribution investments (a performance factor) given the hours DR is expected to operate and the relevant peaks used for sizing different T&D components. To value avoided transmission and distribution costs for the analysis, the Vermont levelized cost employed for screening energy efficiency programs was customized for DR by:

- *Calculating the share of value assigned to transmission and distribution, respectively, based on the historic and forecasted T&D expenditures.* Doing this reflects the fact that the share of money invested in transmission versus distribution varies according to the specific characteristics of utilities.
- *Applying separate performance factors for transmission and distribution that reflect the likelihood that DR would indeed offset specific investments.* The performance factors need to be tailored depending on the hours targeted by the time-varying rate. For example a TOU covers a larger share of hours is more likely to offset distribution investments than a critical peak pricing rate that operates on a maximum of 72 hours

a year. The base performance factors selected are placeholders based on experience, but are not a substitute for a detailed study of the coincidence of particular time varying rates with the time periods relevant for transmission and distribution planning (i.e., the relevant local peaks).

The effective T&D avoided capacity value ranged from \$21.95 to \$42.72 depending on the utility. These values are in line with the EPRI white paper titled *“Quantifying the Benefits of DR in Mass Markets”*, which employed capacity values of \$15/kW- year for transmission and \$12/kW-year for distribution. Prior to detailing the effective transmission and distribution capacity models employed in the analysis, however, it is useful to provide some background on how levelized transmission and distribution capacity costs were estimated.

E.2.2. How Levelized Transmission and Distribution Capacity Costs Are Estimated

The use of levelized T&D capacity value is more common with energy-efficiency, which has a higher likelihood of lowering the need for both transmission and distribution investments than DR given the higher number of hours in which it is reducing energy use throughout the year. Levelized T&D capacity values are typically grounded on identifying the amount of transmission and distribution investments directly attributable to new load growth and dividing those investments by the total growth in load over the time period. This is not a simple task. It is difficult to isolate the T&D investments associated with new load growth, especially because old equipment are often upgraded upon replacement. That said, a levelized T&D capacity value has been employed in Vermont for many years to screen energy efficiency investments. The T&D capacity value is \$135 in 1997 dollars as originally published (\$169 in 2007 dollars). In addition, the 2005 Avoided Energy Supply Costs Study authors developed a calculator for New England that estimates levelized avoided T&D capacity costs that are employed for evaluating energy efficiency programs. The levelized T&D capacity value from the AESC calculator is utility specific.

Importantly, the aforementioned levelized T&D capacity cost estimates were not developed for demand response and, as a result, need to be adjusted for demand response by factoring in the likelihood that the demand response will offset transmission and/or distribution investments based on when, where, and for how long the DR is available. Without such performance factor adjustments, the energy efficiency levelized value likely overstates the avoided transmission and distribution costs.

E.2.3. Avoided T&D Values Employed

Table E-4 reflects how the energy efficiency avoided T&D value was customized for the base peak time rebate program. Two caveats are noteworthy. First, time-varying rates that provide load reduction for more hours (e.g., real time pricing and time of use pricing) would likely have different performance factors, particularly for distribution. Second, these values are not based on detailed study of the coincidence of the critical peak periods with the relevant peaks used in transmission and distribution planning. Obviously, significant changes in these estimates will have significant impacts on the benefit-cost ratio with demand response benefits included. For example, if a 30 percent performance factor was used for distribution for CVPS, the avoided cost for T&D combined would nearly double from a value of \$33.52/kW-yr to \$62.56/kW-yr. This would change the benefit-cost ratio for CVPS from 1.35 to 1.46.

The energy efficiency T&D capacity value was customized for DR and split between transmission and capacity. The DR customized transmission capacity value was calculated by multiplying the share of a utility's transmission investment (out of T&D investments) by the transmission performance factor and by the energy efficiency T&D capacity value. The DR customized distribution capacity value was calculated in similar fashion. The values are escalated as explained in Appendix G.

The transmission and distribution shares for BED, CVPS, GMP, and VEC are based on data about historical and forecast transmission and distribution investments provided to DPS by the utilities. The performance factor for transmission is relatively high because it is generally, though not exclusively, coincident with system capacity. The performance factor for distribution is relatively low because the sizing of many components such as transformers and substations are based on localized peaks that do not necessarily coincide with the critical peak hours of the time-varying rate.

Table E-6
Example of Utility Costs with and without DR

Provider	Energy Efficiency T&D Capacity (kW-Year)	Transmission Share	Transmission Performance factor	Effective Transmission Capacity Value \$/kW-year	Distribution Share	Distribution Performance Factor	Effective Distribution Capacity Value \$/kW-year
BED	\$169.00	16.17%	80.00%	\$21.86	83.83%	10.00%	\$14.17
CVPS	\$169.00	14.06%	80.00%	\$19.00	85.94%	10.00%	\$14.52
GMP	\$169.00	20.98%	80.00%	\$28.36	79.02%	10.00%	\$13.35
VEC	\$169.00	4.27%	80.00%	\$5.77	95.73%	10.00%	\$16.18
WEC	\$169.00	14.87%	80.00%	\$20.11	85.13%	10.00%	\$14.39
Smaller Utilities	\$169.00	14.87%	80.00%	\$20.11	85.13%	10.00%	\$14.39

E.3. AVOIDED ENERGY COSTS

Avoided energy cost estimates are based on the change in energy use by time period valued at the average wholesale cost of energy during those time periods. The energy cost values were based on 2005-2006 wholesale market data from the Vermont zone for ISO-NE and the Vermont residential and commercial load shapes.

For electricity, it is necessary to take into account the hourly variation in the prices and weight it by the amount of energy used/purchased in each specific hour. To better account for avoided wholesale energy costs, the hourly NE-ISO price data was merged with the hourly load shapes for the residential and commercial sector. For each of the rate periods, the total wholesale market cost required to purchase energy in the day ahead market were divided by energy use during those periods, producing a load weighted price by rate period. Tables E-7 lists the wholesale market prices by rate period for residential and commercial medium and large customers. These prices were allowed to grow over time at the general

rate of inflation. This may undervalue the demand response benefits associated with changes in energy use, but the overall magnitude of energy cost savings is quite small so any modification in future prices will have very little impact on the overall net benefit estimates.

Table E-7
Load Weighted Average Wholesale Market Price (\$/MWh)
by Rate Period and Customer Type

	DAY TYPE	Rate period	Residential	Commercial Rate #1 (Medium)	Commercial Rate #2 (Large)
Summer	CPP	Peak	\$119.66	\$120.36	\$119.48
		Off-peak	\$81.68	\$84.30	\$82.46
	Weekday	Peak	\$84.01	\$84.34	\$83.85
		Off-peak	\$64.68	\$65.87	\$64.85
	Weekend	Peak	\$76.59	\$78.36	\$77.19
		Off-peak	\$62.43	\$60.94	\$61.25
Non-Summer	CPP	Peak			
		Off-peak			
	Weekday	Peak	\$77.44	\$77.93	\$78.47
		Off-peak	\$71.62	\$71.07	\$71.36
	Weekend	Peak	\$72.53	\$72.11	\$72.13
		Off-peak	\$68.59	\$65.73	\$66.50

The average market prices by rate period were then combined with estimates of usage by rate period before and after demand response. Next, the expenditures required to purchase electricity with and without the demand response were calculated. Finally the value was grossed up for line losses. The decrease in the expenditures required to purchase electricity for customers constitutes the wholesale market savings associated with the demand response.

E.4. ENVIRONMENTAL BENEFITS

In evaluating demand side programs, the Vermont Department of Public Service employs an environmental adder of 0.87cents (2007 dollars). The adder was applied to the net reduction in energy use due to DR.

APPENDIX F. RELIABILITY BENEFITS

Reliability benefits due to faster outage restoration are widely cited as a benefit of AMI. The concept is intuitive. AMI can help pinpoint the source of outages more quickly requiring utility crews to spend less time testing lines and searching for the outage source and leading to faster outage restoration. In addition, an AMI system can help reduce outage durations during wide scale outages by detecting whether or not power has been successfully restored everywhere while crews are still in the field, thus avoiding crew re-dispatch and longer outages.

The reliability benefits are experienced by customers in the form of reduced outage durations resulting in lower outage costs. Outage costs have been extensively studied and quantified over the last few decades and are a function of outage frequency, duration and other characteristics (e.g., onset time, season, etc.) and customer characteristics (customer type, size, industry, etc.). As a result, the reliability benefits of AMI can be quantified by estimating the difference between outage costs with and without AMI. The calculation requires two major components: the impact of AMI on average outage duration and estimates of average yearly outage costs with and without AMI.

F.1. OUTAGE DURATION IMPACTS

In order to estimate the base outage frequency and duration without AMI, utility specific 2005 and 2006 reliability indices were averaged in order to reduce some of the natural yearly fluctuation in reliability indices. Outage duration is reflected by the Customer Average Interruption Duration Index (CAIDI). Outage frequency is reflected by the System Average Interruption Frequency Index (SAIFI). Ideally, outage frequency and duration estimates would be available by customer sector since they can experience different reliability levels. If medium commercial enterprises tend to be in central areas of cities, they may be closer to field crews and perhaps more likely to be located in areas with reinforced loops. Table F-1 shows the 2005 and 2006 reliability indices provided by the utilities in response to the DPS data request, and the values employed in the analysis.

Table F-1
Average Customer Outage Frequency and Duration by Utility

Utility	CAIDI		Value Used in Analysis	SAIFI		Value Used in Analysis
	2005	2006		2005	2006	
Burlington Electric	0.98	0.64	0.81	0.78	1.7	1.24
Central Vermont [1]	2.30	2.80	2.55	1.8	2	1.90
Green Mountain Power	1.50	1.80	1.65	1.6	1.8	1.70
Vermont Electric Coop	2.00	2.90	2.45	2.4	3.6	3.00
Washington Electric		1.80	1.80		4.4	4.40
Smaller Utilities [2]		1.51	1.51		2.80	2.80

[1] Central Vermont provided outage performance values excluding and including major storms. The value in the table excludes major storms.

[2] Lyndonville and Stowe did not provide 2005 values, as a result a weighted average of the 2006 values was employed for the analysis

Although it is widely accepted that AMI leads to faster outage restoration, there is no consensus regarding the magnitude of the impacts. Few reliable, independent studies attempting to quantify the impact have been conducted. Vendors claim that outage duration can be reduced by as much as 35 percent.¹⁷ In its ongoing AMI business case, Consolidated Edison Company of New York has estimated they can reduce outage durations by XX percent. For the analysis presented here, a 5% reduction in average outage duration was employed in order to err on the conservative side. This value may understate the outage duration reductions experienced by customers.

F.2. ESTIMATING OUTAGE COSTS

Starting in the mid-1980s, utilities in the US conducted a number of customer-outage-cost studies using slightly different survey methods and procedures. Survey-based methods have become the most widely used approach and are generally preferred over other measurement protocols because they can be used to obtain outage costs for a wide variety of reliability and power quality conditions not observable using other techniques.¹⁸ Commercial customers are asked about the value of lost production, other outage related costs, and outage related savings, after taking into account their ability to make up for any lost production. For residential customers, the vast share of outage impacts are not directly observable economic costs and, as a result, they are typically asked about their willingness to pay to avoid outages with specific characteristics. However, because most US utility companies believed these studies could be used by competitors and opponents in the

¹⁷ General Electric Advanced Distribution Infrastructure

¹⁸ Two other outage cost estimation techniques have been employed: scaled macro-economic indicators (i.e., gross domestic product, wages, etc.), and market-based indicators (e.g., incremental value of reliability derived from studies of price-elasticity of demand for service offered under non-firm rates). For a detailed explanation of the different approaches, see : Sullivan, M.J. and Keane, D.M., "Outage Cost Estimation Guidebook", EPRI Research Project 2878-04 Final Report, December 1995

regulatory arena to gain advantage, few of these studies were released to the public domain.

In 2003, the U.S. Department of Energy funded a meta-study of outage costs, making the models to estimate outage costs publicly available and subsequently employed those models to estimate outage costs for U.S. electricity consumers.^{19, 20} Twenty-four studies, conducted by eight electric utilities between 1989 and 2002 representing residential and commercial/industrial (small, medium and large) customer groups were included in the analysis. The data was used to estimate customer damage functions expressing customer outage costs as a function of duration, location, time of day, consumption, and business type, and other factors. The functions can be used to calculate customized outage costs for specific customers and specific durations, allowing the estimation of outage cost for the average Vermont residential and commercial customer.

The publicly available customer damage functions in the DOE study were employed to estimate Vermont customer outage costs with and without an AMI system – i.e., with current outage average durations and with reduced outage durations. Table F-2 shows the relevant regression model for small and medium commercial customers. Table F-3 shows the regression model for residential customers. Please note that the models predict the natural log of outage costs for a single outage. To arrive at the yearly value, the avoided costs per outage were multiplied by the average number of outages experienced by customers during a year.

¹⁹ Leora Lawton, Michael Sullivan, Kent Van Liere, Aaron Katz, and Joseph Eto, "A framework and review of customer outage costs: Integration and analysis of electric utility outage cost surveys" (November 1, 2003). *Lawrence Berkeley National Laboratory*. Paper LBNL-54365. <http://repositories.cdlib.org/lbnl/LBNL-54365> (Note: the study was conducted by LBNL and Population Research Systems, as sister company of FSC).

²⁰ Kristina Hamachi LaCommare and Joseph H. Eto, "Understanding the cost of power interruptions to U.S. electricity consumers" (September 1, 2004). *Lawrence Berkeley National Laboratory*. Paper LBNL-55718. <http://repositories.cdlib.org/lbnl/LBNL-55718>

Table F-2
Tobit Regression Models for Predicting
Small/Medium Commercial Customer Outage Costs

Predictor	Model One		
	Parameter	S.E.	Probability
Intercept	6.48005	0.06525	<.0001
Duration (hours)	0.38489	0.01588	<.0001
Duration Squared	-0.02248	0.0013408	<.0001
Number of Employees	0.001882	0.0001749	<.0001
Annual kWh	1.70E-06	1.21E-07	<.0001
Interaction Duration and kWh	9.46E-08	2.55E-08	0.0002
Morning	-0.6032	0.06151	<.0001
Night	-0.91339	0.07035	<.0001
Weekend	-0.52041	0.04657	<.0001
Winter	0.37674	0.04154	<.0001
Number of Observations	12,356		
Zero Response	6,637		
Log Likelihood	-23,855		

Source: Leora Lawton, Michael Sullivan, Kent Van Liere, Aaron Katz, and Joseph Eto, "A framework and review of customer outage costs: Integration and analysis of electric utility outage cost surveys", p. 31

Table F-3
Tobit Regression Models for Predicting
Residential Customer Outage Costs

Predictor	Parameter	Probability
Intercept	0.2503	0.1468
Duration	0.2211	<.0001
Duration Squared	-0.0098	<.0001
Annual MWh (kWh/1000)	0.0065	<.0001
Log of Household Income	0.0681	<.0001
Morning	-0.0928	0.0061
Night	-0.1943	<.0001
Weekend	-0.0134	0.7454
Winter	0.1275	0.0006
Southeast	0.2015	<.0001
West	-0.1150	0.0228
Southwest	0.5256	<.0001
N	12,057	
Zero Responses	7,319	
Log-likelihood	-20,868	

Source: Leora Lawton, Michael Sullivan, Kent Van Liere, Aaron Katz, and Joseph Eto, "A framework and review of customer outage costs: Integration and analysis of electric utility outage cost surveys", p. 40

Large industrial customers (200 kW or more) were not included in the analysis although they generally have the highest outage costs and would likely also experience reduced outage durations. An AMI system is not necessary for reducing outage costs for large industrial customers; backup generation and power conditioning can lower their outage costs more cost-effectively. In addition, outage costs for large industrial customers vary substantially as a function of detailed inputs that were not readily available (e.g., industry type, backup generation, power conditioning equipment, etc). Finally, Vermont includes industry types such as ski resorts whose outage costs have not been widely studied.

Table F-4 shows the number of customers and the average annual usage employed in estimating commercial and residential customer outage costs. All commercial and residential customers reported in the 2006 utility Annual Reports to DPS were included.

Table F-4
Number of Customer and Average Annual Usage
employed in Estimating Customer Outage Costs

Utility	Commercial customers	Avg. Annual kWh	Residential Customers	Avg. Annual kWh
BED	3,643	53,093	16,197	5,628
CVPS	21,506	41,316	131,483	7,297
GMP	14,004	50,421	78,367	7,430
VCE	3,009	72,416	33,217	7,297
WEC	255	13,151	9,917	6,231
Small Utilities	2,975	29,023	17,698	6,339

Table F-5 shows the remainder of the inputs employed in estimating commercial and residential outage costs. The base average outage duration and frequency varied by utility as reported in Table F-1. The meta-study did not include a regional adjustment for the Northeast since the utilities that conducted outage cost studies in the Northeast did not release the data for the DOE meta-study. As a result, the base scenario, the Northwest (the omitted variable), was employed in estimating outage costs. The distribution of outages across the different onset periods was assumed to be equally distributed across morning, afternoon, and night, given the lack of data about outage onset times in Vermont. Likewise, outages were distributed between weekdays and weekends and winter versus non-winter periods based on the share of total annual hours encapsulated by those periods. For small commercial customers, the average number of customers was obtained by taking the average number of employees from the meta-study. For residential customers, the median Vermont Household income, as reflected by the U.S. Census 2004 estimate,²¹ was adjusted to 2007 dollars (\$47,439) using the GDP deflator.

²¹ U.S. Census Bureau: State and County QuickFacts. Available at: <http://quickfacts.census.gov/qfd/states/>

Table F-5
Other Inputs Employed in
Estimating Customer Outage Costs

INPUT	Residential	Small Commercial
Number of Employees		23.25
Annual kWh	Varies by Utility – Table F-4	
Interaction Duration and kWh	Varies by Utility	
Annual log of income	10.77	
Morning	33.00%	50.00%
Night	33.00%	50.00%
Weekend	28.57%	28.57%
Winter	35.00%	35.00%

F.3. RESULTS

The vast share of reliability benefits are from the commercial sector. The overall benefit per customer varies across utilities because of differences in the average outage duration without AMI, outage frequency, and the share of commercial customers relative to residential customers. Table F-6 lists the outage costs per customer-year with and without AMI, and the net benefit per customer-year for each of the utilities included in the analysis. Table F-7 provides the total avoided costs over the course of the analysis period in both 2007 dollars and in Net Present Value. The avoided outage costs over the analysis period are adjusted for changes in the customer population and were escalated according to the general inflation rate of 2.5%.

Table F-6
Avoided Outage Costs per Customer-Year
by Customer Type and by Percent Reduction in Outage Duration

	% Reduction in Average Outage Duration	BED	CVPS	GMP	VEC	WEC	Smaller Utilities
Residential	0.0%	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
	2.5%	\$0.02	\$0.09	\$0.05	\$0.14	\$0.14	\$0.07
	5.0%	\$0.03	\$0.18	\$0.10	\$0.27	\$0.28	\$0.15
	7.5%	\$0.05	\$0.27	\$0.15	\$0.41	\$0.42	\$0.22
	10.0%	\$0.06	\$0.36	\$0.20	\$0.54	\$0.56	\$0.29
	12.5%	\$0.08	\$0.45	\$0.24	\$0.68	\$0.69	\$0.36
	15.0%	\$0.10	\$0.54	\$0.29	\$0.81	\$0.83	\$0.43
	17.5%	\$0.11	\$0.63	\$0.34	\$0.95	\$0.97	\$0.50
	20.0%	\$0.13	\$0.71	\$0.39	\$1.08	\$1.10	\$0.58
	22.5%	\$0.14	\$0.80	\$0.44	\$1.21	\$1.24	\$0.65
	25.0%	\$0.16	\$0.89	\$0.48	\$1.34	\$1.37	\$0.72
	27.5%	\$0.17	\$0.98	\$0.53	\$1.47	\$1.51	\$0.79
	30.0%	\$0.19	\$1.06	\$0.58	\$1.60	\$1.64	\$0.86
	32.5%	\$0.21	\$1.15	\$0.63	\$1.73	\$1.77	\$0.93
	35.0%	\$0.22	\$1.23	\$0.67	\$1.86	\$1.91	\$1.00
Commercial	0.0%	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
	2.5%	\$3.69	\$23.60	\$12.10	\$35.42	\$34.98	\$17.80
	5.0%	\$7.36	\$47.04	\$24.11	\$70.59	\$69.71	\$35.49
	7.5%	\$11.01	\$70.31	\$36.03	\$105.51	\$104.19	\$53.05
	10.0%	\$14.65	\$93.41	\$47.88	\$140.16	\$138.42	\$70.49
	12.5%	\$18.27	\$116.33	\$59.63	\$174.54	\$172.38	\$87.82
	15.0%	\$21.88	\$139.06	\$71.30	\$208.64	\$206.09	\$105.02
	17.5%	\$25.47	\$161.61	\$82.88	\$242.46	\$239.53	\$122.09
	20.0%	\$29.04	\$183.96	\$94.38	\$275.98	\$272.71	\$139.05
	22.5%	\$32.59	\$206.11	\$105.78	\$309.21	\$305.62	\$155.88
	25.0%	\$36.13	\$228.06	\$117.10	\$342.13	\$338.26	\$172.58
	27.5%	\$39.65	\$249.81	\$128.32	\$374.75	\$370.63	\$189.16
	30.0%	\$43.16	\$271.34	\$139.46	\$407.06	\$402.73	\$205.61
	32.5%	\$46.65	\$292.66	\$150.50	\$439.04	\$434.55	\$221.94
	35.0%	\$50.12	\$313.76	\$161.46	\$470.70	\$466.10	\$238.14
Weighted average	0.0%	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
	2.5%	\$0.69	\$3.40	\$1.88	\$3.07	\$1.01	\$2.62
	5.0%	\$1.38	\$6.77	\$3.74	\$6.11	\$2.02	\$5.23
	7.5%	\$2.06	\$10.12	\$5.59	\$9.14	\$3.02	\$7.82
	10.0%	\$2.74	\$13.44	\$7.42	\$12.14	\$4.01	\$10.39
	12.5%	\$3.42	\$16.74	\$9.25	\$15.12	\$5.00	\$12.95
	15.0%	\$4.10	\$20.01	\$11.06	\$18.07	\$5.98	\$15.48
	17.5%	\$4.77	\$23.26	\$12.85	\$21.01	\$6.95	\$18.00
	20.0%	\$5.44	\$26.47	\$14.64	\$23.91	\$7.91	\$20.50
	22.5%	\$6.10	\$29.66	\$16.41	\$26.79	\$8.87	\$22.99
	25.0%	\$6.76	\$32.82	\$18.16	\$29.65	\$9.82	\$25.45
	27.5%	\$7.42	\$35.96	\$19.91	\$32.48	\$10.76	\$27.90
	30.0%	\$8.08	\$39.06	\$21.63	\$35.28	\$11.70	\$30.32
	32.5%	\$8.73	\$42.13	\$23.35	\$38.06	\$12.62	\$32.73
	35.0%	\$9.38	\$45.17	\$25.05	\$40.80	\$13.54	\$35.12

Table F-7
Total Avoided Outage Costs over Analysis Period
by Percent Reduction in Outage Duration

	% Reduction in Average Outage Duration	BED	CVPS	GMP	VEC	WEC	Smaller Utilities
20 year value (2007 dollars)	0.0%	\$0	\$0	\$0	\$0	\$0	\$0
	2.5%	\$293,233	\$11,181,925	\$3,728,982	\$2,251,037	\$224,132	\$1,158,998
	5.0%	\$585,172	\$22,287,593	\$7,432,383	\$4,486,510	\$446,769	\$2,310,342
	7.5%	\$875,813	\$33,314,351	\$11,109,974	\$6,705,950	\$667,895	\$3,453,977
	10.0%	\$1,165,157	\$44,259,633	\$14,761,535	\$8,908,903	\$887,493	\$4,589,852
	12.5%	\$1,453,200	\$55,120,964	\$18,386,856	\$11,094,932	\$1,105,547	\$5,717,918
	15.0%	\$1,739,944	\$65,895,956	\$21,985,732	\$13,263,616	\$1,322,041	\$6,838,128
	17.5%	\$2,025,385	\$76,582,311	\$25,557,972	\$15,414,549	\$1,536,961	\$7,950,438
	20.0%	\$2,309,523	\$87,177,821	\$29,103,389	\$17,547,343	\$1,750,293	\$9,054,803
	22.5%	\$2,592,358	\$97,680,367	\$32,621,806	\$19,661,622	\$1,962,022	\$10,151,184
	25.0%	\$2,873,887	\$108,087,918	\$36,113,055	\$21,757,030	\$2,172,136	\$11,239,541
	27.5%	\$3,154,110	\$118,398,534	\$39,576,977	\$23,833,224	\$2,380,622	\$12,319,837
	30.0%	\$3,433,027	\$128,610,362	\$43,013,419	\$25,889,879	\$2,587,469	\$13,392,037
	32.5%	\$3,710,637	\$138,721,639	\$46,422,239	\$27,926,682	\$2,792,665	\$14,456,110
	35.0%	\$3,986,938	\$148,730,689	\$49,803,301	\$29,943,340	\$2,996,200	\$15,512,022
20 Year NPV	0.0%	\$0	\$0	\$0	\$0	\$0	\$0
	2.5%	\$220,524	\$6,029,933	\$2,210,384	\$1,322,657	\$171,924	\$806,210
	5.0%	\$440,073	\$12,018,743	\$4,405,605	\$2,636,170	\$342,702	\$1,607,094
	7.5%	\$658,648	\$17,965,001	\$6,585,526	\$3,940,261	\$512,321	\$2,402,617
	10.0%	\$876,246	\$23,867,323	\$8,750,018	\$5,234,665	\$680,767	\$3,192,741
	12.5%	\$1,092,867	\$29,724,373	\$10,898,956	\$6,519,125	\$848,029	\$3,977,434
	15.0%	\$1,308,510	\$35,534,864	\$13,032,219	\$7,793,394	\$1,014,095	\$4,756,662
	17.5%	\$1,523,173	\$41,297,557	\$15,149,693	\$9,057,232	\$1,178,953	\$5,530,395
	20.0%	\$1,736,857	\$47,011,261	\$17,251,267	\$10,310,412	\$1,342,592	\$6,298,601
	22.5%	\$1,949,560	\$52,674,834	\$19,336,837	\$11,552,714	\$1,505,003	\$7,061,253
	25.0%	\$2,161,282	\$58,287,180	\$21,406,303	\$12,783,927	\$1,666,175	\$7,818,324
	27.5%	\$2,372,021	\$63,847,253	\$23,459,570	\$14,003,851	\$1,826,098	\$8,569,787
	30.0%	\$2,581,778	\$69,354,055	\$25,496,549	\$15,212,293	\$1,984,763	\$9,315,620
	32.5%	\$2,790,552	\$74,806,633	\$27,517,154	\$16,409,072	\$2,142,163	\$10,055,798
	35.0%	\$2,998,343	\$80,204,084	\$29,521,305	\$17,594,013	\$2,298,288	\$10,790,300

APPENDIX G. MISCELLANEOUS INPUTS

The analysis employed various growth and escalation factors to adjust starting values throughout the twenty year period included in the analysis. In addition, the year by year nominal dollar benefits and costs were discounted by each utility's weighted average cost of capital in order to account for the time-value of money and provide results in present value terms. Table G-1 summarizes the various adjustment factors employed that have not been explicitly provided in appendices A-F, as well how they were used. The balance of this appendix details how the values were identified.

Table G-1
Summary of Adjustment Factors

Analysis affected	Adjustment Factor	How it is used	Value employed
Operations and DR	Weighted Average Cost of Capital	Used to discount cost and benefit streams over time and estimate the present value.	Varies by utility
	Customer population growth ^[1]	Used to estimate the number of incremental new meters needed and the growth in customers able to provide DR. Also used to adjust the benefits and costs that were presumed to change in proportion to the customer population growth.	0.50%
	General inflation rate	Used to adjust all benefit and cost streams except for meter reading avoided costs, and generation, transmission, and distribution capacity avoided costs.	2.50%
	Tax adjustment	Used to calculate revenue requirements for the IOU's.	32.90%
DR	Coincident peak demand growth ^[1]	A per capita value used to estimate changes in the average customer system coincident demand. It incorporates the forecasted impact of energy efficiency and affects the load impacts over the course of the analysis.	0.03%
	Annual electricity use growth ^[1]	A per capita value used to estimate changes in the average customers annual electricity consumption. It incorporates the forecasted impact of energy efficiency and affects the amount of energy savings due to DR over time.	-0.21%
	Generation capacity escalation rate	Applied to the generation capacity value. It is based on the average growth in costs over the past 10 years as reported in the Handy-Whitman index.	3.00%
	Transmission capacity escalation rate	Applied to the transmission capacity value. It is based on the average growth in costs over the past 10 years as reported in the Handy-Whitman index.	4.08%
	Distribution capacity escalation rate	Applied to the distribution capacity value. It is based on the average growth in costs over the past 10 years as reported in the Handy-Whitman index.	4.96%
Operations	Labor escalation	Applied to meter reading labor costs	3.50%

[1] BED provided population, system coincident peak, and annual usage growth estimates, by sector, based on its own BED specific forecast

G.1. WEIGHTED AVERAGE COST OF CAPITAL

As part of the data request, the individual utilities were asked to provide their weighted average cost of capital (WACC), which was used to discount cost and benefit streams over time and estimate the present value of the benefit cost streams.

Table G-2 shows the weighted average cost of capital employed for each of the utilities and for the joint smaller utilities included in the analysis (Hardwick, Ludlow, Lyndonville, Morrisville, and Stowe). The WACC for the smaller utilities, a weighted average of the individual utility values, with total kWh used as the weights.

Table G-2
Weighted Average Cost of Capital by Utility

Utility	Weighted Average Cost of Capital
BED	5.21%
CVPS	8.52%
GMP	7.50%
VCE	7.80%
WEC	5.00%
Smaller utilities	5.99%

G.2. CUSTOMER POPULATION GROWTH

Customer population was assumed to grow in tandem with population growth. Except for BED, which provided its own estimates of residential and commercial customer growth, the estimates of population growth were based on estimates of the change in population from 2000 to 2030 developed by the U.S. Census Bureau. For Vermont, population was projected to grow from 608,827 in 2000 to 711,867 in 2030.²² This amounts to an average annual growth rate of 0.52 percent. The annual growth rate was applied to both residential and commercial customers for all utilities except BED, which provided its own customer specific forecasts. For BED, residential and commercial customers were projected to grow at an average annual rate of 0.39 and 0.19 percent, respectively.

G.3. GENERAL INFLATION RATE

The general inflation rate is based on the 20 year average (1987-2006) yearly inflation as encapsulated in the chained GDP deflator, and amounts to 2.5 percent per year. This is the same as the approach employed in the Avoided Energy Supply Cost study for New England. The GDP deflator is a broader index than the Consumer Price Index (CPI) and the Producer Price Index (PPI), which only track the costs of goods and services purchased by households and industry, respectively.

²² U.S. Census Bureau, Population Division, Interim State Population Projection, 2005.

G.4. TAX ADJUSTMENT FACTOR

For investor owned utilities, taxes must be considered when making capital investments such as AMI, as they affect the revenue requirements needed to cover the cost of the investment. Tax payments are a function of the assumed depreciation schedule as well as the debt-equity ratio. For purposes of this report, a model provided by CVPS was used to calculate a tax adjustment factor in order to account for the corporate taxes associated with capital investments. With a debt-equity ratio approximately equal to 55/45 and a 20-year tax depreciation schedule for capital investments, we estimated that CVPS and GMP would require an additional 32.9% in revenue over and above the estimated purchase prices of capital equipment (e.g., meters, concentrators, repeaters, etc.) in order to cover both the equipment costs and corporate taxes.

The tax adjustment factor was incorporated when computing the present value of annual capital cost streams, using the following equation:

$$PVRR = \frac{NPV(\text{Cost Stream})}{(1 - \text{Tax Adjustment Factor})}$$

G.5. COINCIDENT PEAK DEMAND AND ANNUAL ELECTRICITY USE GROWTH RATES

Changes in the average customer coincident peak demand and annual electricity use affect the load reduction (MW) and energy savings due to demand response. Given the same peak-to-off-peak price ratio, a 10 percent decrease in average demand leads to bigger load impacts if average hourly demand is 1.0 kW rather than 0.9 kW. Consequently, separate estimates of the system coincident peak and annual energy use growth/decline per customer were developed.

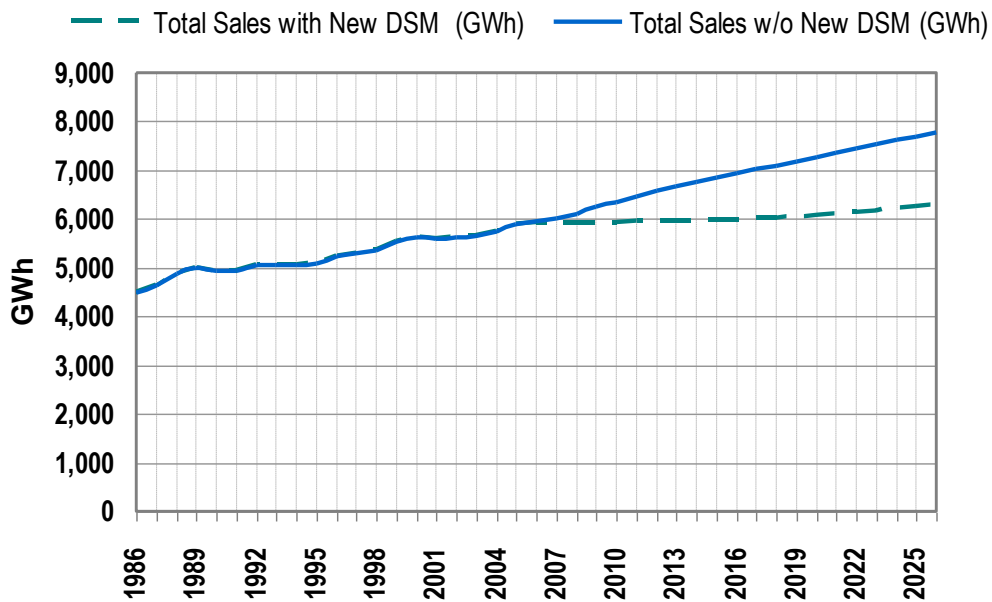
Ideally, the growth factors would have been separately calculated for residential and commercial customers, particularly since the anecdotal evidence and recent trends in A/C usage indicate that contribution of the residential sector to coincident system peak load is expected to grow relative to the commercial sector. However, the DPS long-term forecasts do not distinguish between residential and commercial growth. An additional critical factor in developing the growth rate estimates was the forecasted impact of energy efficiency measures on system peak coincident load and on electricity consumption.

Table G-3 shows the DPS forecasts of Vermont electricity consumption and peak load with and without the projected energy-efficiency impacts. Figure G-1 reflects the projected growth in electricity consumption with and without projected energy efficiency impacts.

Table G-3
DPS Forecast Peak Demand and Annual Sales
With and Without DSM

Year	Total Sales with New DSM (GWh)	Total Sales w/o New DSM (GWh)	Summer Peak with New DSM (MW)	Summer Peak w/o New DSM (MW)	Winter Peak with New DSM (MW)	Winter Peak w/o New DSM (MW)
2006	5,911	5,941	1,084	1,094	1,040	1,063
2007	5,918	6,020	1,098	1,123	1,027	1,076
2008	5,925	6,114	1,109	1,147	1,016	1,090
2009	5,929	6,237	1,126	1,185	1,005	1,110
2010	5,932	6,342	1,131	1,210	991	1,128
2011	5,937	6,447	1,144	1,243	978	1,146
2012	5,952	6,564	1,154	1,274	966	1,165
2013	5,961	6,669	1,162	1,302	953	1,183
2014	5,965	6,761	1,166	1,325	940	1,198
2015	5,967	6,847	1,163	1,341	927	1,214
2016	5,985	6,930	1,165	1,357	919	1,228
2017	6,002	7,012	1,166	1,372	910	1,241
2018	6,024	7,099	1,168	1,389	902	1,255
2019	6,042	7,186	1,170	1,405	894	1,270
2020	6,065	7,277	1,172	1,422	886	1,285
2021	6,102	7,364	1,178	1,439	885	1,299
2022	6,136	7,449	1,183	1,454	883	1,313
2023	6,172	7,535	1,188	1,470	881	1,326
2024	6,207	7,617	1,193	1,486	879	1,340
2025	6,243	7,697	1,199	1,501	877	1,353
2026	6,278	7,777	1,204	1,516	875	1,365

Figure G-1
Historic and Projected Vermont Electricity Consumption
With and Without New DSM



As Table G-3 and Figure G-1 reflect, energy-efficiency is expected to have a significant impact on both peak load growth and overall electricity consumption. These impacts are even more pronounced when viewed on a per capita basis, factoring out the impacts of population growth. Table G-4 presents both the overall average yearly growth rates (including population growth) and the per customer average yearly growth rates, after accounting for the projected 0.52% yearly customer growth. The analysis employed the per customer growth rates for all utilities except BED, which provided its own customer specific forecasts.

Table G-4
Coincident Peak Demand and Annual Use Growth Rates
Overall and per customer, with and without DSM

	Growth Type	With DSM	Without DSM
Overall	Annual Usage	0.31%	1.36%
	Summer Peak	0.55%	1.73%
	Winter Peak	-0.91%	1.32%
Per Customer	Annual Usage	-0.21%	0.83%
	Summer Peak	0.03%	1.21%
	Winter Peak	-1.43%	0.80%

For BED, average residential and commercial electricity consumption per customer was projected to decrease at an average annual rate of 0.44 and 0.26 percent, respectively, after taking into account the impact of energy efficiency programs. On the other hand, average system coincident load was projected to grow by 0.26 and 0.11 percent per customer for the residential and commercial sectors, respectively.

G.6. GENERATION, TRANSMISSION, AND DISTRIBUTION CAPACITY ESCALATION RATES

As detailed in Appendix E, avoided generation, transmission, and distribution capacity costs account for the bulk of the demand response benefits. Importantly, utilities in Vermont and across the U.S. are entering an infrastructure expansion phase, making the potential for avoided costs tangible. At the same time, the utility infrastructure costs have been rapidly rising over the last five years and are projected to continue to grow due in part to higher domestic and international demand in the industry and for large scale construction and raw products (e.g., steel, cement) in general.

The estimates of future infrastructure costs employed in the analysis were based on the average annual escalation over the last 10 years, as reflected in the Handy-Whitman Index. Importantly, the average inflation rate is significantly affected by the start and end points, given the yearly escalation of utility infrastructure costs over the last decade. Table G-5 summarizes the average yearly inflation value changes depending on the period averaged.

Table G-5
Estimated Average Annual Growth of Utility Infrastructure by Analysis Period

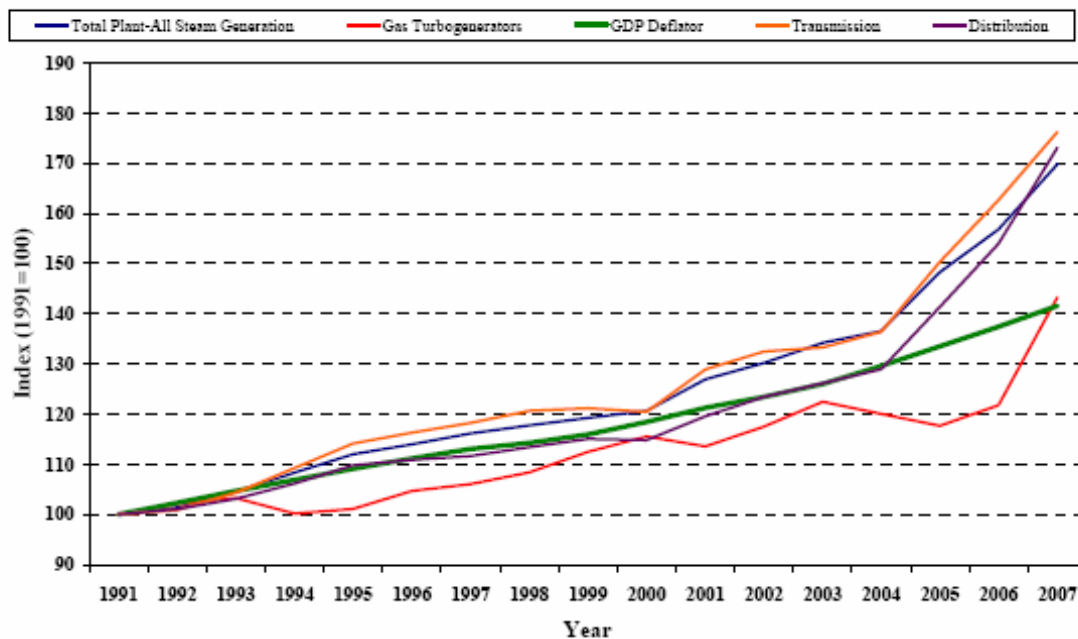
Infrastructure Component	15 year	10 year	5 year	3 year	1 year
Combustion Turbine	2.3%	3.0%	3.8%	5.9%	17.3%
Total Plant - All Steam Generation	3.5%	3.9%	5.5%	7.7%	7.6%
Transmission	3.5%	4.1%	5.9%	8.9%	9.3%
Distribution	3.5%	5.0%	6.8%	9.8%	11.7%
Construction Cost (general)	3.2%	3.4%	4.5%	5.9%	2.8%
GDP Deflator	2.2%	2.3%	2.8%	2.9%	2.5%

When it comes to electricity infrastructure costs, the long term escalation is unlikely to be similar to the escalation experienced over the last 20 years. Clearly, infrastructure investment and domestic demand have been significantly higher for a period of time closer to the present, leading to higher price escalation. In addition, the 1990's reflected a period of transition in the industry as many regions moved away from the vertically integrated utility model, and improved gas power combustion turbines became more common. At the same time, as detailed in the recent Edison Electric Institute (EEI) report on *Rising Utility Constructions: Sources and Impacts*, the spike in utility infrastructure costs in the last few years is in part due to a lag between high utility infrastructure demand and manufacturing capacity for large infrastructure components (i.e., turbines, condensers, transformers). As a result, long term price escalation is unlikely to be as high as it has been in the last 1, 2 or 3 years.²³ Because of these considerations, the average annual escalations over the last 10 years for generation, transmission, and capacity were employed in the analysis.

Figure G-2, borrowed from the aforementioned EEI report, shows how the generation, transmission, and distribution construction costs have grown relative to the general inflation rate (as reflected by the GDP deflator). Clearly the growth in utility infrastructure costs has been most pronounced over the recent period.

²³ That said, NYISO recently recommended that their installed capacity demand curves be adjusted at 7.8% per year based on the average of growth in the prior to years as reflected in the Handy-Whitman Construction Index. More detailed information about the proposed NYISO ICAP demand curves is available at: http://www.nyiso.com/public/webdocs/products/icap/demand_curve_documents/demandcurveproposal10-5-2007_final_V2_redlined_101007.pdf

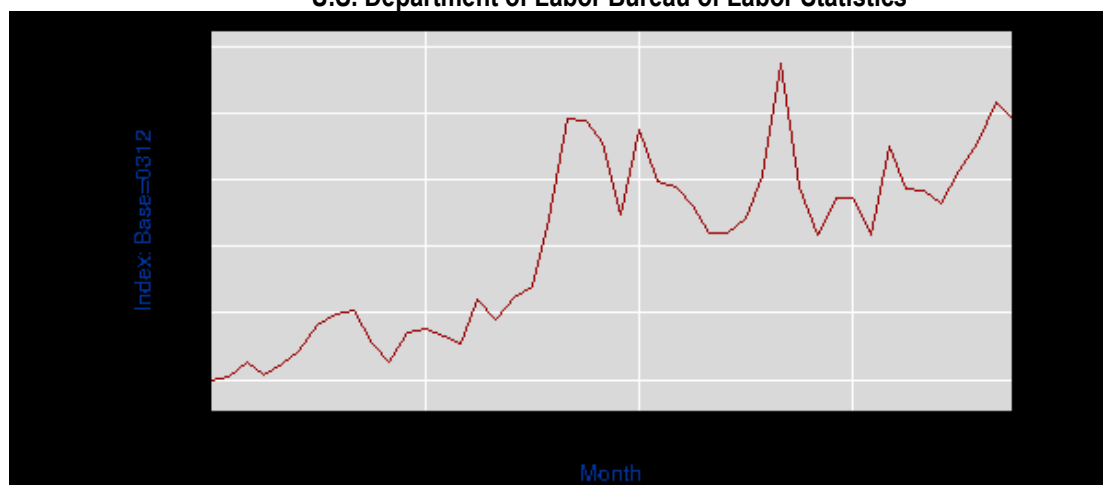
Figure G-2
National Average Utility Infrastructure Cost Indices
(from EEl Report *Rising Utility Costs: Sources and Impacts*)



Sources: The Handy-Whitman® Bulletin, No. 165 and the U.S. Bureau of Economic Analysis.
Simple average of all regional construction and equipment cost indexes for the specified components.

Though only available from 2003 onward, the U.S. Bureau of Labor Statistics's electric power generation producer price index reflects similar escalation in prices. Figure G-3 was drawn from the BLS website and reflects that electric power generation costs over the past three and a half years have increased by roughly 40 percent.

Figure G-3
Producer Price Index for Electric Power Generation
U.S. Department of Labor Bureau of Labor Statistics



While forecasting future prices of generation, transmission, and distribution infrastructure 20 years into the future has a significant amount of uncertainty, it is also clear from historical data that utility infrastructure costs have grown and will likely continue to grow at a faster rate than general inflation.

G.7. LABOR ESCALATION RATE

For the analysis, labor costs were projected to grow at 3.5% per year. The labor escalation rate was applied only to the meter reading labor costs, which include benefits and overheads. The estimate is within the range of escalation rates employed for business in recently filed AMI business cases in the Northeast. In the recently filed Central Maine Power AMI business case, a 3.5% escalation rate was employed. Similarly, Energy East used a labor escalation rate of 4.0% in the recently filed AMI business cases for Rochester Gas & Electric and New York State Electric and Gas, located in western /central New York. In addition, in its preliminary AMI business case analysis, CVPS employed a 4.0% labor escalation rate.

APPENDIX H. DATA REQUEST SURVEY FORM

STATE OF VERMONT PUBLIC SERVICE BOARD

**Petition of the Department of Public Service
for an Investigation into the Use of Smart Metering
and Time-Based Rates**

Docket No. 7307

THE VERMONT DEPARTMENT OF PUBLIC SERVICE'S FIRST SET OF INFORMATION REQUESTS

The Department of Public Service (the "Department" or "DPS") by: June E. Tierney, Esq., Special Counsel, hereby serves the following First Set of Information Requests upon the Burlington Electric Department, Central Vermont Public Service Corporation, Green Mountain Power, Omya, Inc. d/b/a Vermont Marble Power Division, Conservation Law Foundation, Barton Village, Inc. Electric Department, Village of Enosburg Falls Water & Light Department, Village of Hardwick Electric Department, Village of Hyde Park Electric Department, Village of Jacksonville Electric Company, Village of Johnson Water & Light Department, Village of Ludlow Electric Light Department, Village of Lyndonville Electric Department, Village of Morrisville Water & Light Department, Village of Northfield Electric Department, Village of Orleans Electric Department, Town of Readsboro Electric Light Department, Town of Stowe Electric Department, Swanton Village Electric Department, Vermont Electric Cooperative, Inc., Washington Electric Cooperative, Inc. (the "Utilities") in accordance with Public Service Board Rule 2.214 and V.R.C.P. 33 and 34, and requests that VGS answer the requests in accordance with V.R.C.P. 33 and 34 and deliver its answers and all requested documents and materials to the Department's offices in Montpelier not later than **September 18, 2007**. The Utilities are requested to provide two complete copies of all documents. The Utilities are also requested to provide a copy of its answers in electronic format, that is, WordPerfect or other format readable by the Department.

INSTRUCTIONS

1. Please reproduce the request being responded to before the response per V.R.C.P. 33.
2. Responses to any and all Department requests that are contained herein or that may be filed later should be supplied to the Department as soon as they become available to the Utilities. That is, the Utilities should not hold answers to any requests for which they do not have responsive data, documents, etc. until responses to any or all other requests are compiled.
3. V.R.C.P. 33 requires the response to each request to be made under oath by a person competent to testify concerning the response and all documents and exhibits produced as part of the response. With respect to each request, please state (1) the name(s) and title(s) of the person or persons responsible for preparing the response; and (2) the administrative unit which maintains the records being produced or maintains the data from which the answer was prepared; and (3) the date on which each question was answered.
4. Where information requested is not available in the precise form described in the question or is not available for all years (or other periods or classifications) indicated in a series of years (or other periods or classifications), please provide all information with respect to the subject matter of the question that can be identified in the Utilities' workpapers and files or that is otherwise available.
5. These requests shall be deemed continuing and must be supplemented in accordance with V.R.C.P. 26(e). The Utilities are directed to change, supplement and correct their answers to conform to all information as it becomes available to the Utilities, including the substitution of actual data for estimated data. Responses to requests for information covering a period not entirely in the past (or for which complete actual data are not yet available) should include all actual data available at that time and supplementary data as it becomes available.
6. Wherever responses include estimated information, include an explanation (or reference to a previous explanation) of the methods and calculations used to derive the estimates.

7. “Identify,” when used in connection with natural person(s) or legal entities, shall mean the full name and current business address of the person or entity.
8. “Document,” as used herein, shall be construed as broadly as possible to include any and all means and media by which information can be recorded, transmitted, stored, retrieved or memorialized in any form, and shall also include all drafts, versions or copies which differ in any respect from the original. All spreadsheets provided must have all formulae intact and accessible.
9. With respect to each document produced by the Utilities, please identify the person who prepared the document and the date on which the document was prepared.
10. If any interrogatory or request requires a response that a Utility believes to be privileged, please state the complete legal and factual basis for the claim of privilege, and provide the information required by the 5/16/95 order in Docket No. 5771 and respond to the parts of the interrogatory or request as to which no privilege is asserted.
11. If any interrogatory or request is objected to in whole or in part, please describe the complete legal and factual basis for the objection, and respond to all parts of the interrogatory or request to the extent it is not objected to. If an objection is interposed as to any requested documents, please identify the document by author, title, date and recipient(s), and generally describe the nature and subject-matter of the document as well as the complete legal and factual basis for the objection.
12. To expedite the discovery process and the resolution of this docket, the Utilities should contact DPS as soon as possible, and prior to the above deadline for response, if it seeks clarification on any of these information requests.
13. DPS reserves the right to submit additional information requests to the Utilities.

INFORMATION REQUESTS

1. For each tariff, please provide the following information in an Excel Spreadsheet:

- a. Tariff name (e.g., GS1)
 - b. Whether the tariff is currently open or closed to new customers.
 - c. Average number of customers on the tariff in 2006.
 - d. Average annual electricity use in 2006
 - e. Average monthly energy use in 2006
 - f. For TOU tariffs, average energy use by rate period by month in 2006
 - g. Average demand for each month for tariffs with demand charges
 - h. Total annual MWh's sold for all customers on the tariff in 2006
 - i. Total revenue for 2006
2. Technical line losses for 2006 (%)
3. Non-technical line losses for 2006 (e.g., due to theft or other unaccounted for energy)
4. Do you have any load research data that has been collected for any rate class in the last 10 years? The term "load research data" should be construed to mean "hourly (of sub-hourly) data on a representative class of customers."
 - a. If so, what is the most recent year for which the data are available and what rate classes does it cover?
5. Do you have other hourly load data on customers (e.g., because customers are interval metered for rate purposes or because you are deploying interval meters currently)?
 - a. Please describe the number of customers for which such data are available, what tariffs they are on, and the time period over which the interval data is available.

6. Do you have any end-use surveys on your customers?
 - a. If, please describe when the survey was done, for what purpose and generally the kind of information available (e.g., equipment saturation, energy efficiency measures, etc.)
 - b. From whatever sources, please provide the approximate number of residential customers in your territory with the following equipment, if known
 - i. Electric water heating
 - ii. Electric space heating
 - iii. Central air conditioning
7. Have you done a business case analysis (estimating costs and benefits) of AMR or AMI in the last five years?
 - a. If so, please provide documentation of the results of that study.
8. What is your weighted average cost of capital (to be used for discounting purposes)?
9. Please complete and return the attached table, "Docket 7307 Vermont Department of Public Service Smart Metering Survey."

Dated at Montpelier, Vermont, this 28th day of August, 2007.

VERMONT DEPARTMENT OF PUBLIC SERVICE

By: _____
June E. Tierney, Esq., Special Counsel

cc: Service List

Docket 7307

Vermont Department of Public Service

Smart Metering Survey

Thank you for providing the information requested in the tables and questions below. Unless otherwise indicated, assume that the data requested is for the year 2006. If you do not have data for that year but have it for 2005, please provide that data and indicate the year in the Comment/Explanation/Contact (C/E/C) section. If the information you provide is a snap shot in time (e.g., the number of meters in place on December 31, 2006), please indicate so in the C/E/C column. If you do not have the precise data that is requested but you have something similar, please provide the similar data and explain the difference in the C/E /C column. For each entry, please provide a contact name and telephone number in the C/E/C column in case questions arise. If you have any questions, please call Steve George at 415 948-2328.

Table 1					
Meter Assets					
	Number of Meters				
			Polyphase		
Meter Type ²⁴	Single Phase	Network ²⁵	CT ²⁶	CT/VT ²⁷	Comment/Explanation/Contact
kWh					
Demand					
TOU					
Interval					
Type of Meter Read ²⁸	Single Phase	Network	CT	CT/VT	Comment/Explanation/Contact

²⁴ A kWh meter records the amount of electricity used between meter reads. In addition to recording the amount of electricity used between meter reads, a demand meter also reports the maximum kW demand reached in between meter reads. A TOU meter records the amount of electricity used between meter reads for two or more rate periods (e.g., a peak period and an off-peak period). An interval meter records electricity use each hour or sub-hour over a period of time.

²⁵ A network meter is a meter connected to a network grid often found in a high density urban area as opposed to a radial grid area.

²⁶ A CT meter is a meter connected to a current transformer

²⁷ A CT/VT meter is one connected to a current transformer and a voltage transformer. This is also referred to by some utilities as a CT/PT (potential transformer) meter.

²⁸ A manual meter read is one that is done by a meter reader on foot. A Van-based AMR meter read is one that is completed through a radio transmission to a vehicle that drives in the vicinity of the meter. A telephone read is done remotely over a public telephone line. A dedicated network read is one that is done through a fixed communication network (radio or power line carrier) that is dedicated to reading meters.

Table 1					
Meter Assets					
Manual					
Van-Based AMR					
Telephone					
Dedicated Network					
Meter Location	Single Phase	Network	CT	CT/VT	Comment/Explanation/Contact
Indoor					
Outdoor					
Meter Age & Value	Single Phase	Network	CT	CT/VT	Comment/Explanation/Contact
# Meters > 15 years old					
Undepreciated asset value of meters (\$) at end of 2006					
Amortization Period (years) ²⁹					
Other Assets	Number	Annual O&M (\$)			Comment/Explanation/Contact
Hand Held Devices					

²⁹ The number of years over which the meters are depreciated.

Table 1					
Meter Assets					
Non-AMR Equipped Vehicles					
AMR Equipped Vehicles					
Budget for Meter O&M	2005	2006			Comment/Explanation/Contact
\$					
# Meters Replaced					

Table 2			
Meter Density			
Service territory	Square Miles		Comment/Explanation/Contact
Size			
# of Sq. Mi. of Territory with:	Total # of meters		Comment/Explanation/Contact
0 Meters			
1- 100 Meters			
101 – 200 Meters			
201 – 500 Meters			
500+ Meters			
Substations Serving	# of Substations ³⁰	Total Meters Served	Comment/Explanation/Contact
1 Meter			
2 – 100 Meters			
101 – 500 Meters			
501 – 1,000 Meters			

³⁰ Substations owned and operated by the utility. Please indicate in the Comment section whether any substation is shared with a neighboring utility.

Table 2			
Meter Density			
1,001 – 3,000 Meters			
3,001 – 5,000 Meters			
>5,000 Meters			
Feeders Serving	# of Feeders	Total Meters Served	Comment/Explanation/Contact
1 Meter			
2 – 100 Meters			
101 – 500 Meters			
501 – 1,000 Meters			
1,001 – 3,000 Meters			
3,001 – 5,000 Meters			
>5,000 Meters			
Distribution Transformers Serving	# of Transformers	Total Meters Served	Comment/Explanation/Contact
1 Meter			
2 – 5 Meters			
6 – 10 Meters			
11 – 15 Meters			

Table 2			
Meter Density			
16 – 20 Meters			
> 20 Meters			

Table 3				
Meter Reading Operation				
Meter Readers	Company Employed	Contractor		Comment/Explanation/Contact
# of People				
# Full Time Equivalents (FTEs)				
# Union Meter Readers				
# of Non-Union Meter Readers				
Supervisor FTEs				
Average Age of Meter Readers				
Avg. # Years With Company				
# of Normal Cycle Meters Read	Single Phase	Network	CT and CT/VT	Comment/Explanation/Contact
Monthly				
Every Other Month				
Quarterly				

Table 3				
Meter Reading Operation				
Normal Cycle Reads	Annual Labor Cost ³¹	Annual Other Costs	Average Cost per Read	Comment/Explanation/Contact
Manually Read Meters				
Mobile AMR Meters				
Remotely Read Meters ³²				
Off Cycle Meter Reads	All Meters			Comment/Explanation/Contact
Number				
Annual Labor Cost (\$)				
Annual Other Costs (\$)				
Average Cost per Read				
Total Meter Reading Budget	2005	2006		Comment/Explanation/Contact
\$				
Non-Electric Meters Read by Electric Meter Readers	# of Meters			Comment/Explanation/Contact
Water				

³¹ Please include all benefit and other overhead allocations in this total.

³² For remotely read meters, include telecommunications costs in Annual Other Costs category.

<div>Table 3</div> <div>Meter Reading Operation</div>				
Natural Gas				

Table 4				
Call Center and Billing Activities				
Call Type	Number of Calls per Year	Call Minutes per Year	Average Cost per Minute	Comment/Explanation/Contact
Bill Complaints/Inquiries				
Account open/close				
Single Outage				
Storm Related Calls				
Other				
Total				
Call Center Budget	\$			Comment/Explanation/Contact
Labor ³³				
Non-Labor				
Total				
Customer Service Representatives	# of People			

³³ Please include all benefit and other overhead allocations in this total.

Table 4				
Call Center and Billing Activities				
Employees				
FTE Employees				
Contracted				
Union				
Supervisors				
Billing Operations	Number of Bills	Average Cost		Comment/Explanation/Contact
Estimated Bills				
Manual Bills				
Re-bills				
Rereads				
Total				

Table 5 Field Operations			
Field Crew Annual Workload	Number of Trips	Average Cost per Trip	Comment/Explanation/Contact
Single No-Light Trips Actual Outage			
Single No-Light Trips Outage on Customer Side of Meter			
Service Disconnect Trips			
Service Reconnect Trips			
Annual Budget	2006		Comment/Explanation/Contact
Non-storm Related			
Storm Budget			
Storm Expenditures	2005	2006	Comment/Explanation/Contact
\$			
Outage Performance ³⁴	2005	2006	Comment/Explanation/Contact

³⁴ SAIDI = System Average Interruption Duration Index = sum of all customer interruption durations divided by the number of customers
CAIDI = Customer Average Interruption Duration Index = sum of all customer interruption durations divided by the number of customer interruptions
SAIFI = System Average Interruption Frequency Index = total number of customer interruptions divided by the number of customers served
MAIFI: Momentary Average Interruption Frequency Index – not more than 1.5 momentary outages per customer per year. MAIFI represents the average number of momentary outages (short duration "blinks" less than one minute) customers experienced.

Table 5 Field Operations			
SAIDI			
CAIDI			
SAIFI			
MAIFI			